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Thailand
Fuel Option Study

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Industry and Energy Operations Division
Country Department I
East Asia and Pacific Regional Office

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Currency Equivalents

Currency Unit		=	Baht (฿)
Average 1992 —	US$1.0	=	฿25.400
	Baht 1.0	=	US$0.0394
Average 1991 —	US$1.0	=	฿25.517
	Baht 1.0	=	US$0.0392

Acronyms

ADB	Asian Development Bank
bcf	billion cubic feet
BMA	Bangkok Metropolitan Area
BMR	Bangkok Metropolitan Region
BOT	Build-Own-Transfer
bpd	barrels per day
CNG	Compressed Natural Gas
CO	Carbon Monoxide
DEA	Department of Energy Affairs
DEDP	Department of Energy Development and Promotion
DIW	Department of Industrial Works
DMR	Department of Mineral Resources
DPC	Department of Pollution Control
DSM	Demand-Side Management
EGAT	Electricity Generating Authority of Thailand
EIAs	Environmental Impact Assessments
IEAT	Industrial Estate Authority of Thailand
IRP	Integrated Resource Planning
ktoe	kilo ton oil equivalent
kW	kilowatt
kWh	kilowatt-hour
MEA	Metropolitan Electricity Authority
mmb	million barrels
mmcf	million cubic feet
mmcfd	million cubic feet per day
MOF	Ministry of Finance
MOSTE	Ministry of Science, Technology and Environment
mtoe	million tons of oil equivalent
MVA	Manufacturing Value Added
NEB	National Environment Board
NEPO	National Energy Policy Office
NESDB	National Economic and Social Development Board
NGOs	Non-Government Organizations
NO_2	Nitrogen Dioxide
OAEP	Office of Atomic Energy for Peace
OECD	Organization for Economic Cooperation and Development
OEPP	Office of the Environmental Policy and Planning
ONEB	Office of the National Environment Board
PEA	Provincial Electricity Authority
PTT	Petroleum Authority of Thailand
PWD	Public Works Department
RTG	Royal Thai Government
SO_2	Sulfur Dioxide
tcf	trillion cubic feet
TDRI	Thailand Development Research Institute
toe	ton oil equivalent
TSP	Total Suspended Particulates
ULG	Unleaded Gasoline
VKTs	Vehicle Kilometers Travelled

THAILAND

FUEL OPTION STUDY

Table of Contents

ANNEXES

ORGANIZATION CHARTS

PREFACE

This report is based on the findings of missions that visited Thailand between September 1992 and February 1993. The team included: Mohammad Farhandi (task manager), Enrique Crousillat (power and coal), Todd Johnson (environment), Antanasije Kocic (nuclear), and consultants Thomas Fitzgerald (hydrocarbon resources and production) and J. Mazeas (liquefied natural gas).

The study, which was requested by the Government of Thailand, was conducted by the Bank in collaboration with National Energy Policy Office (NEPO), which chaired a steering committee with representatives from the Electricity Generating Authority of Thailand, Petroleum Authority of Thailand, Department of Mineral Resources, Office of Atomic Energy for Peace, National Economic and Social Development Board, Department of Energy Development and Promotion, and Ministry of Finance.

The steering committee provided the study with invaluable advice. NEPO offered constructive comments and worked closely with the mission throughout the task.

Mr. Ernesto Cordoba prepared the energy database and together with Mr. Martin Edmonds provided research assistance.

The report was edited by Ms. Barbara Koeppel.

Ms. Theresa Gamulo and Ms. Hamideh Keyhani processed the report.

The report was cleared by Messrs. Vineet Nayyar, Chief, EA1IE; Danny Leipziger, Lead Economist; the Office of the Chief Economist of the EAP Region; and Callisto Madavo, Director, EA1DR.

Peer reviewers were Messrs. Hossein Razavi, Sudhir Shetty and Trevor Byer.

The report was discussed with Thai authorities and presented at a conference to officials and private sector representatives in September 1993.

Executive Summary

Study Objective and Background

1. The objective of this study is to identify and assess the various fuel options available to Thailand to meet its energy requirements over the next decade or two. The need for such an assessment stems from the increasing demand for energy due to rapid economic growth, the limited expansion of domestic energy resources, and Government concerns about the environmental impact of energy production and utilization as well as the security of supply.

2. Since 1980, energy demand has grown at an average of 10% per year. For electricity alone, it increased by an average of 14% per year over the last five years. However, the various fuel sources from which the country derives its current energy are severely constrained. Hydro power is difficult to develop because of the high costs involved and particularly because of accompanying environmental and re-settlement problems. The country's coal (lignite) reserves are insufficient to meet the increased power generation requirements; moreover, this fuel also creates environmental problems. And, while natural gas is an attractive low-cost alternative (for power generation), resources are limited in the long-run.

3. The study examines the present status and possibilities of piped gas, liquefied natural gas (LNG), lignite, coal, oil and nuclear energy; it provides a fuel strategy based on identifying the most appropriate fuels, as well as where, at what cost and under what conditions they should be obtained to best meet the country's energy needs in different time frames. While attempts were made to confine the investigation to energy supply options, a broader review of the sector was inevitable, particularly with regard to appropriate pricing policies, institutional arrangements and investments needed to implement and sustain the recommended strategy. The study, which was requested by the Government of Thailand, was conducted by the Bank in collaboration with the National Energy Policy Office (NEPO), which chaired a steering committee of the country's key energy entities.

Future Outlook and Energy Demand

4. ***Future Outlook.*** Thailand's overall economic performance in the last 10 years has been very impressive, registering double-digit growth over much of the period. While growth is expected to slow, the outlook continues to be good because of a favorable international economic climate (for Thailand) and the country's sound economic policies and creditworthiness: The study assumes average real GDP growth of 6%-8% over the planning period (1993-2010), which is consistent with the Bank's long-term projections. The stimulus for future growth will continue to be the industrial sector in general, and the manufacturing subsector in particular; the conditions are the availability of capital, sound practices in pricing, investment decisions and allocation of resources, and international competitiveness. With regard to the energy sector, assumptions about its performance include relative stability in the world fossil fuel market, an increase in private sector participation, growth of a corporatized, and, eventually, privatized, organizational structure in the country's energy enterprises, and a policy that promotes less government intervention in energy affairs.

5. Based on the GDP assumptions at the macro level, it is expected that growth at the sectoral levels will be mixed: The industrial sector (which grew at an average of 14% over the last five years and accounted for 35% of GDP in 1992), is expected to slow to about 8% by 2010. However, its share of GDP is expected to increase to about 45% during this time. The transportation sector, which grew at an average of 9% over the last six years and accounted for 7% of GDP in 1992, is expected to grow for several years before declining to about 6% by 2010. Agriculture growth, which averaged 3.4% over the same period and accounted for 13% of GDP, is expected to decline slightly to about 3% by 2010 and its share is expected to drop to about 8% by that year.

6. ***Demand Projection by Sector.*** Projections of energy demand were based on an analysis of total "final" energy needed in each sector, and used GDP elasticity of energy demand as a main indicator. Income and price elasticities were estimated for each, and subsequently calibrated for consistency with those of other countries at a similar stage of economic development. The planning time frame (1993-2010) was divided into three periods (1993-1998, 1998-2005, 2005-2010), that correspond to the major changes expected with respect to the availability of new energy supplies and the structural reform of the energy sector.

7. The analysis of demand indicates that the growth in industrial energy consumption (which averaged 11.4% per year from 1986-1992), is expected to continue, but less intensely than in the past decade. This is primarily because the industrial GDP is expected to grow more slowly than in the past, and also because of the efficiency gained in the use of energy in the sector. This efficiency gain would be mostly the result of energy pricing policy since the sector is assumed to be highly price elastic. Some technical (non-pricing) efficiency gains are also expected, but these will not be significant: An examination of Thai industry indicates that energy-intensive industries represent only about 37% of the total, and are mostly energy efficient because of their new technology and association with international companies. Thus, future gains will most likely come from non energy-intensive industries, primarily the food and beverage industry, where substantial substitution (for woodfuel) is expected to occur. The study estimates that as the result of these factors, sector elasticity will decline from its current level.

8. Growth in transport energy consumption is estimated to increase and remain at a high level for several years before declining by 2010. The rise is largely due to the expected increase in the number of road vehicles, congestion in road transport, and a low level of urbanization. Because the sector is assumed to be price inelastic for most of the planning period, it is expected that the elasticity (which was 1.3 from 1986-1992) will continue to be above one. With regard to the volume of traffic, the analysis shows that real road transportation efficiency, as measured by energy use per passenger mile or per ton of freight mile, actually declined in Thailand from 1982-1991, implying a significant slowing of the average speed of road transport. This would also have a major impact on transport fuel consumption. However, growth in energy consumption is expected to decline by 2010 and elasticity is expected to drop to 1 because as the economy develops, the sector would become more price elastic; in addition, it is expected that an effective mass transit system would be in place and that the country's urbanization factor would increase (to about 0.7, from its current level of 0.2).

9. Because the pattern of past demand elasticity in the agricultural sector is somewhat erratic (possibly reflecting fluctuations in export prices of agricultural products), it was difficult to establish a meaningful correlation (based on past elasticities). However, given the sector's energy share (7%) and its single-fuel use (high-speed diesel), future consumption does not represent a major variable

in total energy consumption. It was assumed that the average elasticity will decline gradually, which would be consistent with the decline in the growth of the agricultural GDP.

10. Growth of energy consumption in the residential and commercial sectors, which averaged 2.9% per year from 1986-1992, is expected to slow. More important, the sector's share of the total energy consumption, which registered a drop (from 32% to 23%), is expected to decline even further, as woodfuels will be replaced by more efficient fuels such as LPG (which is subsidized) and, eventually, electricity. However, the past elasticity value (0.28) was unusually low. In general, energy demand elasticity in the residential and commercial sectors decreases as the country develops (because space-related energy uses such as heating, cooling and lighting are limited for a given building space in spite of continued growth). However, the value seldom falls below 0.3 because about one-third of the energy use (such as for electronic equipment), is basically income-rather than space-dependent. Thus, the elasticity estimate was adjusted to reflect a more realistic value and in line with countries that have similar patterns of consumption.

11. To determine energy needs for the power sector, demand projections were carried out jointly with EGAT, using Bank-prepared input parameters and EGAT's load-forecasting model, which employs an end-use approach that is not inconsistent with the economic assumptions outlined above. The projection indicated that power demand is expected to grow from its current level of 61,000 GWh to 211,000 GWh by 2010, and the average annual growth for the three periods is estimated at 10%, 8% and 6.5%, respectively.

12. Final energy demand projected by the Bank for the various sectors (about 90 million toe in 2010) is 6%-9% higher than the Government forecast, depending on the planning period studied. While projections for the agricultural, residential and commercial sectors are essentially similar, the Bank estimate is 8%-12% higher for transport and 11%-12% higher for industry. This is explained by the Bank approach, which assumes higher energy growth in the industrial and transportation sectors, as discussed above.

13. ***Projection by Type of Fuel.*** To identify the type of fuel required to meet the sectoral demand, the study analyzed end-use constraints along with those related to the price and environmental effects of various fuels. It concluded that (a) consumption of non-commercial energy, such as bagasse in the industrial sector and woodfuels and charcoal in the residential sector, will decline from its current share of 24% to 11% of total energy consumed by 2010, as the country develops; (b) industrial use of gas will be reduced to a level lower than the one currently projected by Thailand, consistent with the priority ranking of the economic value of gas in different applications (this will mean more gas for the power sector); (c) residential and commercial sectors will increasingly use either LPG, as long as it is subsidized, or electricity; gas is not economic as there is no need for space heating, and kerosene, the most common woodfuel replacement, is not subsidized; (d) transport and agriculture will continue to use mainly oil; the role of compressed natural gas (CNG) in transport is expected to be very limited, if any and (e) where end-use application is not a constraint, imported coal, fuel oil, lignite and electricity will compete based on their total economic costs, which include environmental costs.

14. ***Prices.*** The effect of energy prices on various fuel supply options was assessed with respect to the economic cost and value of individual fuels in different sectors and periods, as well as the absolute and relative levels of consumer prices of energy products in Thailand. Economic costs and values of all energy products were related to international prices (for tradeable commodities), or to their economic costs (for non-tradable commodities). The economic cost of imported gas was considered to

be the border price plus the cost of transportation to Bangkok, which the study assumes to be the main consuming center. The economic value of gas and of LNG was based on their netback value for different applications. It was concluded that gas achieves its highest economic value when it substitutes for LPG in the industrial sector (representing about 10% of the gas consumed in Thailand), and next, when used in combined-cycle power plants (presently representing 90% of gas consumption), when substituting, at the margin, for low-sulphur imported coal. Prices of all commercial energy products were assumed to increase at 1% per year, in real terms.

15. With respect to domestic prices, the analysis concluded that current prices for all energy products in Thailand reflect their actual economic costs, except lignite. Thai lignite, due to its poor quality (high sulphur and ash content), cannot be traded in international markets; therefore, its economic cost was based on EGAT's internal transfer price. However, the depletion premium included in this price does not capture the long-term effect of its eventual depletion (or any pollution charges). The study also reviewed consumer prices to determine if, at the absolute level, they create incentives for excessive consumption, and if at the relative level, they create distortions that lead to patterns of consumption not based on the least-cost fuel mix. The study concluded that at both absolute and relative levels, there is no major issue in the energy products' pricing structure. However, certain minor distortions and implied cross-subsidies continue: LPG prices continue to be subsidized; the electricity distribution companies' tariff structure is inadequate, and cross subsidies among consumer groups and regions persist. Although the study recommends that these distortions be rectified, they do not have a significant influence on the fuel supply options considered in the study.

Fuel Options

16. ***Hydrocarbons***. About 6.5 tcf of gas and 250 mmbbl of oil remain to be produced in Thailand, primarily offshore in the Gulf of Thailand. Two features of the country's hydrocarbon basins define the potential role these resources could play in meeting the country's future energy needs. First, they consist mainly of gas; thus, oil is not expected to be an important part of the country's energy resource base. Second, although hydrocarbon resources exist, the basin's geology is so complex that further development will not be easy and costs will be high. However, despite such difficulties, domestic hydrocarbons need to be explored and developed because they still represent the least-cost alternative. Thus, the Government should provide fiscal and contractual incentives to accelerate exploration activities.

17. Given the country's limited gas resources, the possibility of importing gas from neighboring Myanmar, Malaysia and, recently, Vietnam, is often considered in Thailand's energy program. With Myanmar, negotiations have resumed and it is expected that 300 mmcfd gas will be imported beginning early 1998. With Malaysia, the issue is more complex because the two countries possess radically different gas utilization plans and different levels of relative need. Thus, it is expected that the Thai-Malaysian joint development of the JDA gas fields in the Gulf of Thailand will progress more rapidly than will negotiations on importing gas. Nonetheless, the study analyzes the possibility, under a "high" gas scenario, of importing 150 mmcfd of gas from Malaysia to be used in the border areas by the year 2001. This scenario is assumed to begin after Malaysia completes the construction of its internal gas grid that leads to the Thai border. The study did not consider the option of importing gas from Vietnam because that country does not produce enough gas to export.

18. ***Lignite***. Lignite will be a permanent feature of Thailand's energy scene in the next two or three decades because it is one of the few indigenous fuels. Minable reserves are estimated at 1,200 million tons, of which 1,017 million tons are managed by EGAT. It is expected that production and consumption of lignite will continue to increase from the current annual level of 12 million tons to 25-30 million tons in 2005. Based on projected consumption, the reserves will last only until 2020, since EGAT will continue to consume them (primarily as a fallback fuel in the power sector), despite their poor quality and high environmental costs.

19. ***Imported Coal***. This fuel is expected to be the mainstay of Thailand's supply because of its availability in international markets and because its price is projected to remain stable (provided that its environmental impacts are handled appropriately). Industry's consumption of imported coal, which until now has been limited to about 1.5 millions tons per year, is expected to increase significantly. In the power sector, if the imported gas or LNG option do not materialize, coal will be used in a significant way: EGAT estimates it will install about 8,000 MW in imported coal-fired plants from 1997-2006.

20. ***Hydropower***. While the country's hydropower potential is relatively large (estimated at 10,600 MW), only 28% of this capacity has been developed or committed. Moreover, the future use of hydropower is seen as quite limited, since EGAT assumes that its share would represent only 4%-6% of the total power needed over the next 20 years. (The remaining resources are economically less attractive and environmentally difficult to exploit). Therefore, any increase in production will be limited to a few of the most economic, small-scale and environmentally benign projects, primarily for peak generation. The study also reviewed two other potential sources of hydropower: the Mekong river and its tributaries, and Myanmar sources. Although the Mekong basin's hydropower potential is about 37,000 MW (mostly in Laos and Cambodia), developing these resources, particularly from the mainstream of the river, involves complex environmental and resettlement issues. But, as substantial hydropower exists, particularly in the Nam Theun tributary in neighboring Laos, the proposed strategy considers tapping into two hydro projects in Laos; Nam Theun 2 and Nam Theun 1/2. However, hydropower from Myanmar is not considered a feasible alternative over the planning period, because most of these resources have not yet been explored.

21. ***LNG***. Since Thailand may not be able to import gas from neighboring countries, the option of importing liquified natural gas (LNG) was studied. The review focused on its economic viability, as well as its global and regional availability, since Thailand has to compete with Japan, Taiwan and Korea to purchase LNG in the Asian market. The study evaluated the costs of importing about 4 million tons per year by 2000 and 8 million tons per year by 2005. Among the various LNG supply sources studied, Qatar and Malaysia were found to be the most viable. With regard to receiving terminals, four possible sites were evaluated: One is on the west coast, at Ranong, and three are closer to Bangkok, in the vicinity of Map Ta Phut. The study concludes that LNG is an option which clearly deserves a more thorough investigation, including direct negotiations with potential LNG suppliers, because the netback value of gas in Thai power sector is very high. However, the study points out that the cost of imported LNG may be higher in future, when suppliers have to invest in grass-root plants. For this reason, it was concluded that the issues of availability and cost need to be assessed more fully.

22. ***Nuclear***. This option was examined because EGAT's plan calls for a 2x1000 MW plant to be built and commissioned by 2006. The analysis of the nuclear option became complicated because of two factors: (a) the decision on whether a country should produce nuclear energy goes beyond mere

economics and covers a host of other issues (some of which are difficult to quantify such as the regulatory measures needed to protect the public and evaluate the risk); and (b) even with items that should be quantifiable (such as costs), calculations are difficult because estimates made in the past are no longer useful, since key parameters have changed significantly over the past ten years. Despite these complexities, the study attempted to answer two questions. First, is a nuclear program, as an alternative source of fuel for power generation, economically viable for Thailand? And, second, can the country's institutions meet the challenges posed by the nuclear option? A brief discussion of the last issue was essential, because the Government may introduce nuclear technology to meet other strategic and policy objectives, regardless of the economics involved. The study concluded that the answers to both questions were negative because the economic costs of building and operating nuclear plants would be far higher than other fuel options. The analysis shows that EGAT estimated the average capital costs for the two units at US$1,430 per kw, a figure substantially lower than the one projected by the Bank missions (US$2,250 per kw average). Thus, using the higher figures, the nuclear alternative was eliminated from the planning period (up to 2010).

23. ***Demand side management (DSM).*** Although its scope is limited, given the importance of integrated resource planning for power generation, the study found that DSM represents the least-cost supply (saving) option. However, at present, EGAT does not yet take its full value into account, because its ultimate effectiveness is still too early to judge.

Power Expansion

24. EGAT's power development plan (PDP) for 1992 shows an existing installed capacity of about 11,000 MW, and a series of on-going projects which would add 8,300 MW of new generating capacity from 1993-1997. Also, it calls for expanding the system by approximately 12,000 MW from 1997-2006. The PDP includes various technologies, including combined-cycle power plants, lignite and oil, as well as imported coal (starting in 2000) and nuclear in 2006. The Bank mission reviewed the PDP and recommended (a) using more appropriate unit costs for gas turbine, combined-cycle and nuclear plants, (b) attributing a higher and more realistic cost to outages (currently EGAT is using US¢8 per kw, compared with generally accepted estimates of US¢50 to US$2-$3 per kw), and (c) giving more weight to the benefits from the DSM program. In order to assess the impact of the above adjustments and create new generation expansion plans, EGAT carried out various optimization analyses using Bank assumptions. EGAT's model eliminated the nuclear-based power plant and promoted plants fueled by natural gas.

Comparison of Power Generation Costs

25. Based on total costs (including those related to the environment), the unit costs of power generated with different fuels were calculated. A comparison shows that the least-cost power alternative (besides the DSM program and hydro import from Laos, which, at US¢2.1 and US¢2.6 per kWh, represent the best scenario but have limited scope), is the use of gas in a combined-cycle plant (US¢4 per kWh), followed by lignite with high-efficiency FGD (US¢5.1 per kWh), low-sulphur imported coal without FGD (US¢5.2 per kWh), LNG (US¢5.4 per kWh), low sulphur fuel oil without FGD (US¢5.7 per kWh), and low sulphur coal with FGD (US¢5.6-US¢6.1 per kWh, depending on whether FGD is low efficiency or high efficiency). Gas-fueled combined-cycle remains the least-cost power generation alternative for a wide range of fuel costs, capital costs and plant factors. Except for the nuclear plant (which EGAT includes because it assumes lower capital costs), EGAT's expansion

plan is generally consistent with the Bank mission estimates for generation costs: It highlights the importance of domestic gas and lignite, and as these two energy sources decline, it anticipates that additional demand will be met by imported gas, coal and LNG.

Environment

26. The environmental consequences of the various fuel options were assessed for the industrial and power sectors (with regard to atmospheric emissions). The principal atmospheric pollutants are sulfur dioxide (SO_2), particulates (TSP) and nitrogen oxides (NO_x); and, based on the country's current energy development plan, if no additional pollution control technologies are applied and environmental policy remains unchanged, emissions of the three pollutants will more than double by the year 2000 and increase roughly four-fold by the year 2010, compared with 1990 levels. The study evaluated the costs of pollution control technology of different supply options. The study also concluded that regardless of the environmental policy adopted, pollution control technology will be required in the power and industrial sectors.

27. Natural gas (either piped or in the form of LNG) is by far the cleanest fuel available to Thailand's power and industrial sectors. The study estimates that total SO_2 emissions could be reduced by 2.5 million tons over the next 20 years if reasonable quantities of natural gas or LNG for the power sector could be obtained either from increased domestic production or from neighboring countries or international markets.

28. With regard to lignite, despite the high costs of pollution-control technologies (high-efficiency FGD), the study concluded they should be installed on existing and new lignite-fired power plants because of the enormous amount of SO_2 emissions that would otherwise be emitted. In addition, although industrial lignite is of slightly better quality than that used for power generation, its expanded use (by industry) would result in high levels of TSP and SO_2 unless additional pollution-control technologies are introduced. Thus, the study also found that major industrial users of lignite, such as cement plants (which, alone, consumed 70% of the industrial lignite in 1991), should be equipped with appropriate pollution control facilities.

29. Low-sulfur (0.5%) imported coal --whose use is expected to rise-- contributes roughly one-third the amount of TSP and one-seventh the amount of SO_2 per unit of useful energy, without pollution controls as compared to domestic lignite. However, since Thailand's air pollution standards are likely to become more stringent over the next two decades, pollution control technologies may be needed (in low-sulphur coal plants) to reduce emissions beyond that which can be achieved from improving fuel quality alone. But, in contrast to the Government's stated plan of installing high-efficiency FGD on all new imported coal-fired power plants, the study demonstrates that similar levels of SO_2 can be reduced at substantially lower cost by installing low- or medium-efficiency FGDs on low-sulfur coal plants. For the purpose of this study, it is assumed that imported coal (for both the power and industrial sectors) will be of the low-sulphur type, and that the imported coal-fired power plants will be equipped with low-efficiency FGDs.

30. Despite the perception that fuel oil will play only a minor role in future power generation in Thailand, the study found it will be an important "swing" fuel under all fuel supply scenarios. If the current practice of burning high-sulfur (3%) fuel oil continues, SO_2 emissions from fuel oil-fired power plants under EGAT's PDP could roughly double by 2006, accounting for

approximately 16% of total SO_2 emissions from the power sector in that year. However, if low-sulfur (0.5%) fuel oil is used, SO_2 emissions from fuel oil-fired power plants could be reduced by more than 80%. Moreover, if warranted, additional reductions could be achieved by installing medium-efficiency FGD equipment. In the industrial sector, where the costs of installing such equipment to numerous small consumers would be prohibitive, the use of low-sulfur fuel oil could reduce SO_2 emissions by 290,000 tons in the year 2006. Thus in this analysis, it is assumed that future fuel oil (for both the power and industrial sectors), will be of the low-sulphur variety, but there is no provision for FGDs.

31. The cost elements used in the proposed fuel option strategy include mitigation measures needed to meet environmental standards; these were integrated (internalized) at two stages. The first was with regard to industry, when the final sectoral energy demand was estimated by type of fuel and the end-use application was not a constraint. In these cases, the choice of fuel was based on its internalized costs. For example, with lignite, the price include the cost of high-efficiency FGD units in all future cement plants. In the same fashion, the prices used for imported coal and oil would be based on the use of low-sulphur coal and low-sulphur fuel oil in all industrial applications. Second, when decisions were made on the type of fuel for the power sector, environmental costs were internalized, taking into account additional issues unique to that sector --such as the various types of power plants that operate in EGAT's present system, the existing projects and future plans for plant retirement. For these decisions, it was assumed that future lignite-fueled power plants would use high-efficiency FGDs (at a cost that is about 28%-30% higher than the base case). For the existing plants, EGAT has stated it will retrofit units 8-11 with FGDs, and that it is studying the retrofitting of units 4-7. Other steam plants were assumed to use low-sulphur coal (with low efficiency FGD) and low-sulphur oil. In the residential and commercial sectors, the issue did not arise because the competing fuels (for the declining non-commercial fuels), were only LPG and electricity.

Institutions

32. The institutions in the energy sector were reviewed in order to assess the qualities and arrangements needed to carry out and sustain the recommended supply options. The assessment was carried out from two perspectives. First, state enterprises that supply energy to the economy were studied to broadly determine if they supply energy to the country efficiently, and if they could perform as well if their present operations were expanded but the modes remained the same; also, if they could perform efficiently in the event the modes were changed. The assessment was not intended to establish whether the enterprises should be responsible for the implementation and operation of the recommended option; rather it was to determine if they have the capability to carry out the expanded tasks, in the event the present structure of the sector remains the same. Second, Government agencies involved in the energy sector were evaluated to determine whether they and their organizational arrangements adequately meet the sector's institutional needs.

33. The study concluded that major state enterprises such as EGAT and PTT, which now function as well-run, efficient entities, could, in the future, conduct all aspects of electricity, coal and hydrocarbon operations, including LNG. Both companies have substantial experience in implementing and operating energy projects and commercially-based activities (despite their public status). Still, the handling of various supply options proposed need not be limited to these two entities; instead, it is quite possible that LNG could be handled by a different entity, or that the import of gas and hydro could be conducted by other enterprises. Given that the objectives of the this study are to recommend viable supply options and examine the institutional and legal framework to the extent it may create obstacles to

implementing the recommended option, the report concludes that both PTT and EGAT have the managerial and operational capabilities to supply commercial energy in any form and mode, except nuclear. However, the study also concluded that the investment required to finance the energy projects needed over the next decade or two, involves a large volume of capital. And, it is this factor that should drive the entities toward restructuring as corporatized or privatized enterprises. In the meantime, two actions are encouraged: The Government should amend the Acts that created EGAT and PTT and provide them with the latitude to expand their business activities and strategic planning; this would include diversifying their financial portfolios-- to help them implement the recommended supply option (if these entities are asked to assume the task).

34. With respect to Government agencies, two institutional issues are critical. One is the need to strengthen NEPO, which is an effective central body that could provide overall sector coordination and devise a coherent sector strategy; the second is the need to create an independent regulatory framework for energy affairs. It was concluded that as energy issues become more complicated, the number of NEPO's staff and their level of expertise must be increased to meet the new demands, particularly in fields such as economic pricing, LNG and nuclear matters, as well as in dealing with the private sector. With regard to regulatory framework, because new sources of private funds are needed, a decision on establishing an independent regulatory body must be made as soon as possible: A set of legally binding, transparent and practical rules and regulations must be in place to assure the private companies that their investments and future income, market entries and exits are predictable.

Option Evaluation

35. ***Ranking of Supply Options.*** The above analysis, which applied end-use constraints and economic and environmental costs (total costs), produced a matrix of projected demand for the individual fuels that could meet the country's energy requirements in different time periods over the next two decades. To develop an appropriate strategy to meet the projected demand, various commercial supply options were examined; those that did not appear viable --such as nuclear energy-- were eliminated. The remaining options, were ranked according to their total economic costs as follows.

36. Demand Side Management. Over the broad spectrum of supply options, the least-cost source of supply (saving) of energy is through the on-going DSM program. Based on the program's cost (US$190 million) and the capacity and energy it would save from 1992-1996 (225 MW and 1,400 GWh per year), the unit cost of additional energy saved would be only US¢2.1 per kWh. However, the quantity of energy saved would represent less than 4% of the total expansion needs of the power sector during the period. Assuming the program succeeds and its scope is subsequently increased, the total capacity saved during the planning period would be an estimated 2000-3000 MW, or about 10% of the power sector expansion needs. Hence, this option has limited potential.

37. Hydropower. The import of hydroelectricity from Laos through one of two potential Nam Theun projects, which would cost an estimated US¢2.6 per kWh, represents the next least-cost source of supply. However, this option is also limited because even if both projects (Nam Theun 2 and Nam Theun 1/2) are implemented, they would add only about 800 MW of capacity to EGAT's northeastern grid by the year 2000. While other hydro sites may develop in Laos, the time needed to

evaluate and implement any programs would be beyond the study planning period, as would potential hydro imports from Myanmar.

38. Natural Gas. This option ranks third, provided the projected cost of production and price of import remains below the opportunity value of the gas in Thailand. Although the cost of producing domestic gas in Thailand is relatively high (due to the complex geology of the region) and the cost of importing gas is expected to be even higher, the value of gas, when used in a combined-cycle power plant, is considerably enhanced because of its inherent characteristic which result in higher thermal efficiency than lignite, coal or fuel oil. Therefore, when this higher "opportunity" value is taken into account, despite a higher cost, gas could still compete with other fuels. In the Thai context, the maximum opportunity (economic) value of gas is determined to be US$4.50 per mmbtu. Accordingly, if the cost of delivered gas (domestic, imported or even LNG) at the point of consumption becomes higher than this value, then the economy should switch to the next best alternative fuel which, for Thailand, is assumed to be low-sulphur imported coal. Therefore, gas is the third most economic supply option, provided its delivered cost in Bangkok does not exceed US$4.50 per mmbtu.

39. Based on this value and the economic costs of various domestic and imported gas options, the study concludes the following: (a) domestic gas, at an average economic cost of US$2.00 per mmbtu, returns the highest benefits to the economy, but resources are limited and the supply is projected to decline after 2005; (b) given that the economic cost of imported gas from Myanmar, delivered at Bangkok, is estimated at US$2.26 per mmbtu (for 300 mmcfd), which could result in a final negotiated price of around US$2.81 per mmbtu (mid-point between the minimum economic cost and maximum economic value), this option may offer the second highest benefits within the gas supply options and (c) since the economic cost of Malaysian gas delivered at Bangkok would be high, gas is not likely to be imported from Malaysia for some years, unless it is for consumption in the Thai-Malaysia border areas.

40. Lignite. Lignite should theoretically be the next fuel choice because its use in power plants, even after including the cost of high-efficiency FGD, results in a power cost of about US¢5.1 per kWh; however, due to insufficient reserves, it cannot be considered the replacement fuel at the margin. Thus, it is considered the "fallback" fuel: A ceratin fixed share (about 20%) will continue to be used to meet the country's primary energy requirements.

41. LNG. Although the cost of LNG is considerably higher than most other fuels, this option was analyzed because of its high netback value (identical to gas) in combined-cycle power plants. Further, the use of LNG may become a more attractive option, when the country's gas reserves decline after 2005, and it needs LNG to fuel the approximately 8,000 MW combined-cycle plants that the country will have installed by that year. The two major assumptions are that its delivered cost at the point of consumption would be less than its economic value (i.e., less than US$4.50 per mmbtu), and that the supply would be available. Under certain scenarios, the first assumption holds: The highest-cost scenario for regasification and inland transmission of LNG-based gas in Thailand is about US$ 0.83 per mmbtu. Considering that the present CIF price of LNG in the Far East is about US$3.6 per mmbtu for countries significantly farther from LNG sources than Thailand, this gives a maximum total delivered cost, at the point of consumption, of about US$4.4 per mmbtu for LNG. This is still lower than the value of gas to the Thai economy. The margin would be considerably higher for Malaysian LNG delivered at Rayong. Given that the margin varies widely, Thailand must conduct intensive discussions with potential suppliers of LNG to determine quantities and costs more accurately.

42. Low-Sulphur Imported Coal. This option is considered the long-term replacement fuel, and thus the mainstay of the future fuel supply in the power sector: It is readily available from international markets and its future price is expected to remain almost flat, provided adequate measures are taken to limit pollution emissions. The cost of electricity generated through the use of imported coal is estimated at US¢5.6 per kWh, which includes the cost of low efficiency FGD.

43. Oil. The Government policy has been to limit the use of oil. In the power sector, oil is considered a "swing" fuel. In fact, EGAT's power development program (PDP) does not include any new oil-fired plants throughout the planning period (year 2006). The attempt to suppress oil demand stems from a combination of factors, including the strategic one --which is to rely less on oil-- as well as oil price fluctuations and pollution. The latter had a major impact on the study because it assumed that low-sulphur oil would be used in the future, which is considerably more expensive than the medium-sulphur fuel oil EGAT currently uses. The cost of power generated with low-sulphur fuel oil (without FGD) was estimated at US¢5.7 per kWh, placing it among the more costly fuels. Despite this policy, it is thought that Thailand would still need to rely on oil (in fact, many of EGAT's gas-fired plants are designated as dual-fired gas-oil plants) because alternative fuels that could replace it are limited, particularly in the transport sector (which uses oil exclusively).

44. ***Supply Scenarios and Evaluations***. Given the above economic ranking for different supply options, several scenarios were developed that were based on the expectations regarding the availability and total cost of various options. The physical availability and least-cost criteria were considered to be the "technical" factors that affect the different supply options, in contrast to the "policy" factors discussed in para. 49. The scenarios for each of the three periods are discussed below.

45. During the first period, 1993-1998, the status quo will alter only slightly with respect to type and source of fuel consumed because any new initiatives beyond the projects already underway cannot be completed in this time. The additional energy needs of this period will be met through increased production of domestic resources (gas and lignite) and new imports of oil and coal (the latter in small quantities). However, crucial decisions about the type and source of energy for the second and third periods will need to be made during the first period (such as importing LNG or low-sulphur coal). Also, negotiations must intensify with the Laotian government about importing hydroelectricity and with the Myanmar and, possibly, Malaysia, about importing gas.

46. The second period, 1998-2005, will involve major changes in the energy supply because by 1998, the country's demand for energy will exceed the presently identified supply options. Given the recent setback in negotiations with Malaysia and the signing of a production-sharing agreement between PTTEP and Myanmar, gas imports from the latter in the range indicated (300 mmcfd by 1998) seem increasingly likely. With respect to Malaysia, as discussed earlier, under a "high "gas scenario, Thailand might import 150 mmcfd for use in the Songkhla/Khanom region (close to the border) by 2001. However, if Thailand is unable to obtain a significant volume of gas from Myanmar or any from Malaysia, the country would have to import low-sulphur coal or obtain LNG (if LNG could be obtained at a price that could compete with coal on an economic-value basis). The choice between the two will depend on various factors that include prevailing prices, environmental considerations, availability of supply, end-use applications, and the Government's strategy to diversify fuel sources and secure a reliable fuel supply. Therefore, two scenarios were analyzed; under the first, Thailand will import LNG and under the second, it will import a significant amount of coal.

47. Predicting the energy scene during the third period, 2005-2010, is more complicated. If, during the second, Thailand imports gas from Myanmar and Malaysia, it would increase these during the third period, because the relatively low incremental costs involved in expanding pipeline capacity would serve as an incentive to increasing the gas throughput. Similarly, if Thailand imports LNG in the second period, it would increase this during the third period by constructing one additional plant --as the incremental cost would be less. However, if neither imported pipe gas nor LNG had materialized during the second period and the country's bulk energy demand was met only through significant imports of coal and oil, then, during the third period, nuclear may be an option because the Government policy might be to reduce its reliance on imported energy in general and on oil in particular, regardless of the economic cost of the nuclear option.

48. Therefore, except for the first period which has only two scenarios (a "high" and "low" gas, since LNG would not be available during the first period), within the other two periods three supply scenarios have been envisage. The "high" gas scenario assumes a great deal of gas would be produced domestically and also imported from Myanmar, along with a modest amount from Malaysia. The LNG scenario assumes a small amount of gas would be produced domestically and imported from Myanmar, but significant quantities of LNG would be imported from international markets. Finally, the "low" gas scenario assumes a significant quantity of low-sulphur coal would be imported and a small amount of gas would be domestically produced and imported from Myanmar. While in each scenario one fuel is dominant (either gas, LNG or imported coal), the economy would continue to use substantial amounts of other fuels.

49. The choice of fuel supply will depend not only on the physical availability and economic viability of a particular supply option, but also on the prevailing policy framework that supports the structure of the energy sector. Therefore, the study subsequently re-examined the above technical-based scenarios in order to assess the impact of the prevailing policy factors in each period (such as organization, ownership, regulation, and financing of the sector) on the supply option.

50. The study concluded that, during the first period, the policy factors (as with the technical factors) will not affect the country's present supply options: Even if a major policy decision on restructuring the sector were initiated today, its implementation would still not begin before the end of the period (1998). Moreover, the investment decisions and sources of funding --which are often the impetus to policy changes-- for major projects scheduled to be implemented in this period have already been taken and secured. However, although major restructuring will not occur during the first period, fundamental decisions about the sector's investment needs for the second and third periods will have to be made at this time --largely because new sources of capital must be found to finance the massive infrastructure required for the country's growing energy demand projected for these next periods. Because the driving force for sector reform is raising capital (as opposed to gaining efficiency, since energy entities in Thailand are already reasonably efficient), the Government and the entities will both focus on capturing the economic values inherent in the energy sector, and hence will try to maximize profit taking rather than efficiency gains.

51. As a result, it is expected that the state energy enterprises will be corporatized by the beginning of the second period (1998-2005). The reason for the emergence of a corporatized structure is that further commercialization within the existing mode of operation would not yield substantially greater benefits (either to the Government or the entities), since under the present arrangements, the main actors would remain unchanged, as would their motivations: Entities would attempt to meet certain performance criteria, such as efficiency standards set by the Ministry of Finance for PTT, rather

than a set of commercial objectives; the environmental policy would continue to be dictated by mitigating risks through physical and technological means (such as installing scrubbers and high efficiency FGDs), rather than through financial and policy measures (taxes and incentives); and the regulatory mode would continue as before, with the Government providing ad hoc regulatory directives to reverse the adverse consequences of market shortcomings, rather than acting as an independent regulatory body providing incentive-type regulations. Although both the Government and the entities would attempt to maximize efficiency under this regimen, the course would not be sufficient to ensure profit maximizing operations. Hence, further commercialization within the existing mode would not enable the sector to meet its capital-raising objectives. Conversely, the full privatization of the two major energy entities may not be the solution during the second period either, because selling them during this time would not result in optimum prices: Their operations would not have been tested on a fully commercial basis, and some of their investments, particularly those of PTT, might not yet have generated positive returns.

52. It is under these circumstances that the most likely outcome is that the state energy enterprises would be corporatized by the beginning of the second period (1998-2005). It is also expected that the regulatory framework would be completely independent because, in the absence of a qualified and independent body, any benefits gained under a commercialization/corporatization drive would be eroded after a while.

53. The picture after 2005 (the third period) becomes somewhat fuzzy with respect to the sector organization and ownership structure because the matrix of supply options will include numerous possibilities resulting from the interaction of various technical and policy factors. It is expect that after 2005, the corporatization would be well-rooted and that the sector would move towards partial privatization of the entire enterprize or full privatization of some of the units and subsidiaries. With regard to the regulatory framework, it is expected that as the need for private sector participation increases and the corporatization process deepens, the need for an independent and effective regulatory framework would also increase.

54. ***Cost-Benefit Analysis Results.*** When the economic rankings (of the various supply options) were placed in the context of different supply scenarios, the following was concluded (see Table 6.2 of the text):

(a) The country's energy supply requirements will almost triple, reaching about 120 million toe in 2010. While under each scenario one fuel is dominant, the role of other fuels will not diminish: Under all three scenarios and periods, lignite will meet 10%-12% of total energy requirements because it is an indigenous fuel and the Government would want to benefit from its economic rents. Also, the share of oil will remain almost constant, because although the Government is suppressing the oil demand in industry and power, transport sector demand, which relies only on oil, is growing faster than other sectors. Finally, because the potential hydro projects are environmentally difficult to develop, its share of hydro will remain almost unchanged during the study time frame, at about 4%-8%. Therefore, the scenarios evolve around three imported fuels: gas, LNG and coal.

(b) The economic cost of supplying energy to the Thai economy will range from US$7.2 billion in 1998 to US$15 billion in 2010. This cost does not include the US$40-50 billion required for capital investment.

(c) When costs alone were considered, under the LNG scenario, the cost of a composite unit of energy (a combination of oil, gas, coal, lignite, LNG and hydro) was the highest in the second and third periods (LNG would not be available in the first). Under low-sulphur coal scenario, the unit cost is lowest in the second and third periods if Thailand has to pay a high price for imported gas. If Thailand would pay a low price for imported gas, the cost of gas option would be lower.

(d) However, when the economic values of the same composite unit of energy were evaluated, the net benefits (the difference between the economic costs and values) of the three options indicate the following: (i) In 1998, the gas scenario has a higher net benefit than the coal option; (ii) In 2005, its benefits are significantly higher than both the coal and LNG options (because domestic gas production reaches its plateau), while the net benefits of LNG are higher than the coal option (iii) by 2010, the net benefits for gas drop slightly as compared with previous periods (because domestic gas production declines), but are still higher than both the coal and LNG options, while those for LNG and coal are almost identical.

(e) The potential annual savings from the gas option during, for example, the second period, range from US$600 million to US$1,300 million, depending on whether the gas option is compared with coal or LNG, and on the purchasing price of the imported gas.

(f) The total quantity of energy required under the LNG and imported coal options is slightly less than that required under the gas option: Under these two scenarios, the cost of power generation would be higher and this would slightly affect the demand for electricity due to its high price elasticity in the industrial sector.

55. ***Proposed Strategy.*** The proposed strategy calls for the Government to take actions in four key areas: (a) initiating and or concluding a variety of measures needed to bring the optimum supply option to fruition; (b) mobilizing the finances to implement the recommended option; (c) implementing other measures necessary to ensure the sustainability of the selected option and (d) establishing a framework for environmental policy and standards in the country.

56. Regarding the first area, the Government must:

(a) Closely monitor the on-going DSM program of the power sector in order to assess its long-term potential, and if it succeeds, increase its scope;

(b) Initiate and conclude negotiations with Laos, as soon as feasible, to import hydroelectricity; participate, as a joint venture, in financing the project so as to mobilize funding for Laos and assure that country of Thailand's long-term commitment to the project;

(c) Accelerate the exploration of the country's hydrocarbon basins and review the existing fiscal regime and contractual terms so as to relax them and provide incentives for increased private sector participation in exploration and production; in particular, accelerate the development of JDA gas fields;

(d) Intensify negotiations with Myanmar and Malaysia about importing gas, and conclude, by the end of 1994, whether gas import from either country or both is a viable option;

(e) Enter into active discussions with the potential supplier of LNG and conduct a more detailed evaluation on the economic, institutional and environmental feasibility (including site selection) of importing LNG so as to determine, by the end of 1994, if this option can materialize;

(f) Conduct the preparatory work for importing coal, which would include selecting a site for handling it, conducting a pre-feasibility study for the port facilities, and completing it by the end of 1994; and

(g) Re-examine the country's hydro sites to determine whether through improved financial packaging and better environmental mitigation plans, some of them could be developed (given the country's critical needs for new sources of energy).

57. With regard to the second area, the private sector alone, which is currently very active in Thailand's energy sector, such as in all upstream operations in oil and gas, in refining, producing petrochemical and lube oil and distributing oil products, it would not be able to undertake investment of the magnitude envisaged without Government support, either directly or through mediation for private and international funding. Nonetheless, the private sector role needs to be increased because it is doubtful if this size investment and expenditure can be sustained by the public sector alone, without constraining the country's economic growth. The Bank-proposed strategy supports the implementation of a least-cost program without addressing the appropriate proportion between public and private investment. However, as discussed in the text, this issue need to be addressed soon, and comprehensively, since the mix of public and private sector in Thailand's energy sector will significantly affect the country's fuel supply options.

58. The third area involves other measures the Government must take that are not directly related to supply options, but necessary to ensure the sustainability of the selected option. With regard to pricing policy, the future price of gas to be supplied by PTT to EGAT should be based on a long-term formula in line with international standards; that is, it must establish separate agreements for firm and interruptible gas supply according to the scope of the on-going study, which should be finalized as soon as possible.

59. In general, the level and structure of electricity tariffs are adequate. However, the tariff system has some distortions, the most important of which is the lack of an adequate structure for distribution companies, which pay no capacity charges. In order to ensure the success of current peak-shaving efforts (which would reduce future investments), a cost-based structure should be developed for the distribution companies.

60. Also, the transfer price used by EGAT for domestic lignite must be reviewed with the goal of evaluating a more realistic depletion premium. In this regard, special care should be taken to incorporate a sufficiently long time frame into the planning process in order to capture the long-term effects (of the depletion premium).

61. With regard to institutions, NEPO should be strengthened. Institutional building efforts should include increasing the number of its staff and training activities in areas such as energy pricing,

international oil and gas markets and the skills needed to design and monitor contracts with private power suppliers: also, the organization should introduce a management information system.

62. A suitable legal and regulatory framework for the energy sector should be designed and applied. It should be the subject of a careful study that would define the roles to be played by the Government, regulatory entity or entities, energy sector enterprises and interest groups. Key issues would be the type of regulatory entities that could most effectively create an enabling environment for private sector participation and privatization of public energy entities. Further, issues such as whether there should be a single regulatory body or different regulators for each sub-sector must be carefully assessed.

63. The Department of Mineral Resources should be strengthened so as to increase its capacity to assess hydrocarbon reserves, conduct preliminary explorations and analyze the country's fiscal regime in the context of gas-utilization economics.

64. Finally, several actions are recommended in order to strengthen PTT's and EGAT's commercial activities and prepare the two entities for future privatization:

(a) The Government should amend the acts creating PTT and EGAT, providing them with the latitude to expand their business activities and strategic planning, which would include diversifying their financial portfolios;

(b) The present onlending arrangement between the Government and the entities --through which the Government does not charge an onlending fee-- needs to be re-examined so that PTT and EGAT could operate on a fully commercial basis;

(c) The implied monopoly position that PTT and EGAT enjoy, such as the limitation applied to cogeneration and restrictions on lignite production, should be reviewed in order to allow greater private participation; and

(d) The software and data base EGAT uses in its planning process should be examined along the lines presented in Chapter III.

65. With regard to the fourth area, the Government must finalize environmental policies and standards on which investment decisions could be calculated and the least-cost schemes of energy supply could clearly be determined. This study recommends the following measures with regard to pollution control technologies:

(a) Incorporating into the design of all future lignite-fired power plants a high efficiency FGD and assessing each of the existing plants to establish an economic way of retrofitting them with a combination of low- and high-efficiency FGDs; and

(b) Using low-sulphur fuel oil and imported coal in both the power sector and industry, and incorporating their costs into the planning process of future power and industrial plants.

CHAPTER I

BACKGROUND AND OVERVIEW OF THE ENERGY SECTOR

A. Background

1.1 Over the last decade, energy consumption in Thailand has been strongly affected by rapid economic growth and changes in basic economic structure. Responding to these changes, and attempting to avoid infrastructure bottlenecks that could hamper economic performance, the Government is cooperating with the World Bank to search for the best mix of fuels to meet future requirements.

1.2 In 1991, the total supply of commercial energy in Thailand was about 33 million tons of oil equivalent (toe) --a two-and-a-half fold increase over 1980-- and the figure was growing at an average rate of 11% per year. Petroleum represented 62% of the total, natural gas 21%, lignite 13%, hydro power 3% and coal 1%, and 60% of the supply was imported. In addition, Thailand consumed about 10 million toe of renewable energy in 1991, mainly in the form of wood fuels. Despite the country's impressive economic growth (of 10% a year, for the last 6 years), per capita energy consumption and the type of energy consumed is that of a low-income developing country, which is a modest 540 kg. oil equivalent of energy per capita and a relatively high share (25%) of traditional fuels. This pattern is due to the large rural population and the relatively high price of commercial energy (compared with rural income levels), which places commercial energy beyond the reach of the lower-income group. Table 1.1 shows past supply of primary energy by sources.

TABLE 1.1: THAILAND - Primary Energy Supply by Sources
(million toe)

Energy Sources	1985	1991
Oil	10.5	20.5
Natural Gas	3.2	7.0
Hydro Power	0.9	1.1
Coal/Lignite	1.6	4.5
Renewable	11.2	10.8
Total	27.4	43.9

Source: DEA, Thailand.

1.3 Commercial energy, particularly oil and gas, plays a critical role in the economy because (a) the country is only modestly endowed with these resources and (b) the dramatic industrialization in recent years has led to a sharp increase in their consumption. In fact, demand continues to far exceed domestic supply and this gap is likely to increase in the future, in view of the continued and rapid economic growth expected and the uncertain prospects of discovering any additional major oil and gas reserves. Because expansion of domestic resources appears to be limited, the country is likely to rely even more heavily on energy imports, which is problematic.

1.4 Final commercial energy consumption in the economy is dominated by the transport sector, which in 1991 accounted for 39%, followed by the industrial sector (31%), and residential and

commercial sectors (24%). Traditional fuels continue to represent a significant, albeit rapidly declining share of energy consumption in the rural residential sector (see Table 1.2).

TABLE 1.2: THAILAND - Final Energy Consumption by Sectors
(million toe)

Sector	1985	1991
Transportation	6.0	11.9
Industry	5.4	9.6
Residential and Commercial	6.1	7.2
Agriculture	1.4	1.8
Total	18.9	30.5

Source: DEA, Thailand.

1.5 Providing fuel in the power sector is a particularly critical issue, since electricity demand has grown by about 14% a year over the last five years: To meet projected demand for the year 2000, the Electricity Generating Authority of Thailand (EGAT) needs to double its generating capacity from the current 9,000 MW to about 18,000 MW. In 1991, the fuels used to generate power included natural gas (40%), lignite (25%) and heavy oil (24%), while hydro was about 9%. However, EGAT's choices are increasingly limited. First, the remaining supply of hydro is difficult to develop because of high costs and environmental and resettlement problems. Second, lignite reserves are insufficient to meet the increased requirements and its use creates environmental problems, as well. However, if gas (which is the most preferred fuel) becomes unavailable, then EGAT must include locally produced lignite plants (or imported-coal-based plants) and dual-firing capability (to supplement gas with fuel oil) in its master plan.

B. Study Objective

1.6 The objective of the study is to identify and assess fuel options to meet the country's requirements over the next decade or two. It examines the situation of piped natural gas, liquified natural gas (LNG), lignite, coal, oil and nuclear energy, with a view to develop an economically rational, environmentally sound, and financially viable strategy. The report provides a fuel strategy that identifies the fuel that is most appropriate as well as where, at what cost and under what conditions it should be obtained to best meet the country's energy needs in different time frames. The study was requested by the Government of Thailand and the Bank carried it out with the National Energy Policy Office (NEPO), which sponsored the study on behalf of the Government and chaired a steering committee which included representatives of the country's key energy entities, as well as the Bank.

C. Resource Endowment

1.7 Thailand has a diversified energy resource base, consisting of petroleum (oil, condensate and natural gas), lignite, hydropower, biomass and geothermal energy (which is still at an exploratory

stage in the northern region). However, these resources are limited, which means Thailand is a net importer of energy.

1.8 Given the geological features of the country's hydrocarbon basins, crude oil is not expected to be a major contributor. At the end of 1992, there were about 245 million barrels of proven and probable oil reserves. Of these, about 177 million barrels are condensate, which would have to be produced in association with offshore gas, and about 68 million barrels are crude oil. Additional oil reserves are estimated at about 440 million barrels, of which about 350 million barrels are condensate and 90 million barrels are oil. Production is currently limited to Phet crude from the Sirikit oil field, which produced 22,000 barrels per day (bpd) in 1991. In addition, about 27,000 bpd of condensate were produced in association with gas from offshore fields in the Gulf of Thailand. To meet the oil demand, Thailand imported 160,000 bpd of finished petroleum products, and 220,000 bpd of crude for processing it in its three local refineries.

1.9 An attractive option for power generation, both economically and environmentally, is the use of natural gas in combined-cycle power plants. However, the country's natural gas resources are limited and it is assumed that Thailand will not be able to produce sufficient gas to meet demand over the next 40-50 years time period. Natural gas has been discovered mostly by companies looking for oil. At the end of 1992, the remaining proven and probable reserves were about 6.5 trillion cubic feet (tcf). Gas production in 1992 was 850 million cubic feet per day (mmcfd), of which 750 mmcfd were produced from the offshore fields. There is ample demand for natural gas in the foreseeable future: A conservative estimate indicates the country's demand will continue to exceed the supply by over 60% for the next 15-20 years. Considering the country's limited supply, Thailand has looked into importing piped gas from neighboring countries (potentially from Malaysia, Myanmar and, recently, Vietnam), or importing it in the form of LNG from international markets. While the Government has not formally adopted a gas-use policy, the present allocation is based on the ranking of the economic value of gas in different applications: When industry substitutes gas for LPG, it achieves the highest ranking, even higher than when it is used in the power sector. However, in the latter, it reaches its highest value when used in a combined-cycle power plant. Table 1.3 shows past gas consumption in Thailand.

TABLE 1.3: THAILAND: Natural Gas Consumption
(mmcfd)

Sector	1989	1991
Feedstock	69	100
Industry	20	40
Power	252	554
Total	341	694

Source: DEA, Thailand.

1.10 Coal resources are all relatively low grade; the quality is generally categorized as lignite, although some deposits verge on being sub-bituminous. Information about reserves is somewhat ambiguous since no common standards are used to classify them. Total minable reserves are estimated at around 1,200 million tons which, according to current projections for lignite demand for power generation and industry, should last for about three decades. Lignite therefore, is expected to play a long-term albeit limited role as an energy source.

1.11 Hydroelectric potential is estimated at about 10,600 MW, of which only 3,000 MW have already been developed or committed. The remaining potential is, in general, economically less attractive and environmentally quite difficult to develop. Thus, the potential for hydro would be limited to small/medium scale new projects and low-impact pumped-storage stations.

D. Issues and Strategy

1.12 In addition to the issue of insufficient domestic energy resources, which motivates the present study, other strategic issues in the energy sector which could negatively affect the various fuel options are:

(a) ***Environmental impacts***. Environmental impacts of energy production and consumption have become a topic of public debate and a real constraint to developing high-impact technologies such as lignite power generation and hydropower. The Government recognizes the importance of this issue and is committed to developing the sector in an environmentally sound manner.

(b) ***Size of investment***. The heavy burden of energy investments on public resources is recognized as a potential constraint to economic growth. As a result, the Government is investigating various avenues for promoting private sector participation in the energy sector, aimed at mobilizing greater financial resources as well as introducing greater efficiency incentives.

(c) ***Staff expertise and regulatory framework***. The Government has pursued sector efficiency objectives, including certain institutional reforms, with conviction, and the results are impressive. However, two key issues remain. First, NEPO, which was established to create, coordinate and advise on energy policy, and which has significantly improved policy analyses and recommendations over the past seven years, lacks the expertise to adequately perform some of these functions. This is becoming an increasingly important issue, due to complexity of the energy decisions the country must face. Second, there is no independent regulatory body.

(d) ***Subsidies and cross-subsidies in energy prices***. In past years, different measures have been introduced to correct energy price levels and adjustment mechanisms. However, some distortions remain in the price structure of petroleum products (LPG continues to be subsidized) and in electricity tariffs (power distribution companies pay no capacity charge), as well as in the price of domestic lignite. The Government is aware of the potential negative effects of these minor distortions on investment decisions and inter-fuel substitution and is taking steps to narrow differences consistent with the structure of economic costs.

(e) ***Energy conservation***. Rational use of energy has been recognized as essential to cope with the economic, financial and environmental costs of energy supply. Thus, energy conservation is a formal objective of Thailand's energy sector policy which is beginning to move towards an integrated resource approach that focuses both on supply and demand solutions.

CHAPTER II

ENERGY DEMAND

A. Future Outlook

2.1 Thailand's economic performance over the last ten years has been impressive, registering double-digit GDP growth over much of that period. The economy was increasingly diversified, with substantial shares attributed to manufacturing. While growth is expected to slow due to a persistent trade deficit, the outlook continues to be good. This optimism is based on: (a) a favorable international economic environment for Thailand; (b) sound economic policy including trade liberalization and the abandonment of import substitution; and (c) continuing credit-worthiness that provides external funds for financing the higher growth. The Bank's long term projection is for Thailand's economy to grow at 6%-8% over the next 10-15 years.

2.2 The stimulus for future growth will continue to be the industrial sector in general, and manufacturing in particular. The projected growth assumes that the country will continue its sound economic policies (particularly as they relate to pricing and investment decisions and to resource allocation), remain internationally competitive and achieve greater political stability. Within the energy sector, it assumes that private sector participation and deregulation will increase, Government participation will be at arms-length, population growth and the size of households will decline and as consumer incomes rise, the demand for higher quality energy will also rise.

2.3 Although average GDP growth during 1986-1992 was 10.2%, it is expected to decline from 8.9% in 1992 to 6.5% by 2010. For the purpose of this analysis, it is assumed that GDP will grow at an average of 7.8% per year during 1993-1998, 6.7% during 1998-2005 and 6.5% during 2005-2010. The industrial sector, which grew at an average of 14% during 1986-1992, is expected to slow over time, from 11% in 1992, to about 8% by 2010. However, its share of GDP is expected to increase from 35% in 1992 to about 45% by 2010. Transportation GDP, which grew at an average of 8.9% in the same period, is expected to increase from 6% in 1992 to an average of 7.5% during 1993-1998, and then slowly decline to 6.1% by 2010. Its share of GDP is expected to remain fairly constant during the period at around 7%. Agriculture grew at an average of 3.4% and the sector's share of GDP was 13% in 1992. However, its growth is projected to decline slightly, from 3.3% in 1992 to 3.1% by 2010. Its share of GDP is also expected to drop from 13% in 1992 to about 8% by year 2010. Table 2.1 shows historical data on aggregate and sector GDP, and Annex 1 shows the projections for GDP and energy growth.

TABLE 2.1: THAILAND - Past Sectoral GDP and Energy Consumption

YEAR	OVERALL		INDUSTRY				TRANSPORT				AGRICULTURE				RESIDENTIAL/COMMERCIAL			
	FINAL ENERGY (KTOE)	GDP-72 PRICES (MMBAHT)	ENERGY (KTOE)	%	INDUSTRY GDP (MMBAHT)	%	ENERGY (KTOE)	%	TRANSPORT GDP (MMBAHT)	%	ENERGY (KTOE)	%	AGRIC. GDP (MMBAHT)	%	ENERGY (KTOE)	%	SERVICES GDP (MMBAHT)	%
1981	15551	318439	4489	29	91005	29	4431	28	20641	6	1072	7	65093	20	5559	36	141700	44
1982	16221	331380	4913	30	93102	28	4511	28	22711	7	1128	7	67082	20	5669	35	148485	45
1983	17022	355408	4727	28	100548	28	5075	30	24536	7	1243	7	70061	20	5977	35	160263	45
1984	18272	380738	5116	28	109044	29	5916	32	27074	7	1292	7	73977	19	5948	33	170643	45
1985	18856	394113	5418	29	107999	27	6025	32	28171	7	1355	7	78539	20	6058	32	179404	46
1986	19556	413489	5426	28	116236	28	6492	33	30191	7	1405	7	78755	19	6233	32	188307	46
1987	21048	452635	5758	27	131142	29	7428	35	32699	7	1441	7	78601	17	6421	31	210193	46
1988	22927	512467	6210	27	154460	30	8520	37	36207	7	1523	7	86629	17	6674	29	235171	46
1989	26574	574195	7877	30	179288	31	10169	38	40650	7	1639	6	92386	16	6889	26	261871	46
1990	28904	631610	8744	30	207213	33	11368	39	45069	7	1803	6	90711	14	6989	24	288617	46
1991	30479	678761	9533	31	230424	34	11910	39	47413	7	1827	6	93288	14	7209	24	307636	45
1992	32389	739171	10382	32	255771	35	12696	39	50258	7	1922	6	96367	13	7389	23	336776	46
AVG ANNUAL GROWTH RATE																		
1981-86	4.69	5.36	3.86		5.02		7.94		7.90		5.56		3.88		2.32		5.85	
1986-92	8.77	10.17	11.42		14.05		11.83		8.86		5.36		3.42		2.88		10.17	
ELASTICITY																		
1981-86	0.87		0.77				1.00				1.43				0.43			
1986-92	0.86		0.81				1.33				1.57				0.28			

Notes:
- Elasticity for residential/commercial sector is based on overall GDP
- Figures for year 1992 are based on mission estimates.
- Elasticity in the residential/commercial sector is considered too low in relation to the experience of both developed and developing countries, such as Korea, Taiwan, and the United States, whose elasticities are above 0.6 (see text).

Source: Thailand/Bank Mission.

B. Demand Projection By Sector

2.4 The total sector demand projection was based on an analysis of final energy consumption in various sectors. The GDP elasticity of energy demand was used as a main indicator for projecting demand. Although at the aggregate level this indicator may be crude, when used at a highly disaggregated level, as in this study, it provides accurate results. Several key assumptions were made with respect to the stability of price and income elasticities over the planning period (1993-2010). Past price elasticities were not used because the Oil Fund, which was operating until two years ago, sent erratic and contradictory signals to consumers; therefore, it is difficult to establish, with a reasonable degree of accuracy, a correlation between past price increases and consumption patterns. However, the lack of such a past correlation may not be important because in a high-growth country such as Thailand, price elasticities do not have a significant impact. Further, real energy prices have increased very little over the past ten years (in fact, the real price of energy declined over this period, mainly because of a fall in the international price of key energy products). With regard to the planning period, the price of crude oil and coal is projected to increase an average of only 0.95% and 0.85% per year respectively, and that of LNG is assumed to be tied to the price of crude oil. Thus, it is assumed that the price increase of all energy products will be about 1% per year in real terms and that the Government will not raise prices above this level. With respect to sectoral income and price elasticities, the basic assumption is that they both tend to fall over time and with growth in the country's overall income level. In the industrial sector, income elasticity is projected to decline from 0.8 to 0.6 during the planning period, but the sector's price elasticity will be high (about 0.9). The transport sector is assumed to have the highest income elasticity (1.3) and the lowest price elasticity (0.3), while the agricultural sector is expected to follow the pattern of price and income elasticities for a single fuel, since about 96% of agricultural fuel is diesel oil. In the residential and commercial sectors, the income elasticity of 0.28 is considered rather low, compared with other countries (para. 2.11); thus, it is assumed to be higher (0.60) and a price elasticity of 0.6 is used.

2.5 The time frame used for projecting energy demand is 1993-2010. It has been divided into three periods (1993-1998, 1998-2005 and 2005-2010), each representing the potential for a major change with respect to availability of new energy supply and the structure of the sector (para. 6.19).

2.6 Energy consumption during 1986-1992 grew at an average of 8.8%. During this period, transport grew an average of about 11.8% per year, followed by industry (11.4%), agriculture (5.4%), and residential and commercial sectors (2.9%). Table 2.1 also shows past energy consumption and each sectors' share.

2.7 ***Industrial Sector***. Energy consumption in the industrial sector grew at an average of 11.4% per year during 1986-1992, which implied a GDP elasticity of 0.81. Its share in total energy consumption increased from 29% in 1981 to 32% in 1992. Within manufacturing, which accounted for the bulk of energy consumption growth, food and beverages consumed the highest share of energy (38% in 1991). Although energy consumption in construction has also grown substantially, since this sector represents only 2% of total industrial energy consumption, its impact has been negligible. Table 2.2 shows energy consumption in various industrial sub-sectors in 1991.

TABLE 2.2: THAILAND - 1991 Industrial Energy Consumption by sub-sector and type of fuel
(ktoe)

Sectors	Coal & Lignite	Oil	Gas	Elec.	Non-Commercial	Total	Growth (%) 86-91	Share (%)
Bev. & Food	116	460	0	317	2753	3646	6	38
Textiles	29	442	0	370	0	841	13.4	9
Paper	225	93	0	74	0	392	18.5	4
Fab. Metals	0	48	0	199	0	247	29.5	3
Chemical	109	196	150	262	87	804	27.8	8
Non-Metals	1024	682	210	240	118	2274	16	24
Basic Metals	55	173	0	137	18	383	15	4
Others	1	591	0	89	18	699	17	7
Subtotal Mfg.	1,559	2,685	360	1,688	2,994	9,286	12	97
Construction	0	194	0	0	0	194	9.5	2
Mining	0	53	0	0	0	53	0	1
Total Industry	1,559	2,932	360	1,688	2,994	9,533	11.9	100

Source: Thailand/Bank Mission.

2.8 In comparison to other countries with similar levels of industrial activities, industry in Thailand consumes a relatively low share of energy because energy-intensive industries represent only 37% of the total, and that proportion is not expected to increase significantly. In fact, given the thrust of the economy, the opposite is expected --that the share of less energy-intensive industries will grow. Besides, the energy-intensive industries are, for most part, energy efficient, because they are either in joint ventures or have license agreements with large international firms.[1/] The energy intensity in the chemical and basic metal industries corresponds well with countries such as Japan, which has similar energy intensity values for the same industries. Therefore, no significant decline is foreseen in the current level of elasticity resulting from efficiency gains in the energy-intensive industries. However, efficiency could be gained in less energy-intensive industries because of substantial woodfuel substitution as well as increased consumption of electricity. Accordingly, a marginal and gradual decline in the GDP elasticity of energy demand in the industrial sector is expected resulting from increased efficiency in less-energy intensive industries and a more mature response to income and price elasticities. Based on these calculations, it is estimated that the overall elasticity will decline in this sector, from its current level of 0.81 to about 0.60 towards the end of the third period. Thus, the future energy demand of the industrial sector is estimated at 15,415 ktoe in 1998, 22,813 ktoe in 2005 and 28,510 in 2010. The share of energy consumption in industry is expected to remain unchanged at about 32%.

2.9 ***Transport Sector***. The share of transport energy consumption has been increasing continuously, from 33% in 1986 to 39% in 1992. Energy growth in this period averaged about 11.8%, which implied an energy demand elasticity of about 1.3. This is relatively high when compared with other countries such as Taiwan (1.08), Singapore (0.42), Japan (0.72) and the US (0.65) over the 1983-1988 period. This high level is due to an increase in the number of road vehicles as well as in the volume of traffic. Table 2.3 shows the breakdown of energy consumption for different transportation modes. This data indicates that road transport had the highest energy growth as well as the highest share of consumption.

1/ The petrochemical industries in Thailand are associated with Himont, Dow Chemical and Mitsui.

TABLE 2.3: THAILAND - Past Transport Fuel Consumption by Mode of Transportation (ktoe)

Modes	1982	1986	1991	Annual Growth 1982-91 (%)	Annual Growth 1986-91(%)	1991 Share (%)
Road	3,177	4,490	8,775	12.0	14.3	73.7
Rail	83	103	116	3.8	2.4	1.0
Water	367	779	936	11.0	3.7	7.9
Air	884	1,120	2,083	10.0	13.2	17.5
Total	4,511	6,492	11,910	11.4	12.9	100.0

Source: Thailand/Bank Mission.

2.10 High consumption in transport is basically due to congestion and a relatively low level of urbanization. While automobiles in Thailand may be fuel-efficient, severe traffic has lowered the sector's fuel efficiency significantly. As shown in Table 2.4, real road transportation efficiency, as measured by energy use per passenger mile or per ton of freight mile, actually declined at an average of about 2% per year during 1982-1991. This decline suggests that congestion has slowed the average speed of road transport. With regard to the second factor, in countries with adequate mass transit systems, transport energy elasticity is known to be inversely related to urbanization (the fraction of population living in metropolitan areas). The urbanization factor for Thailand was 0.20 in 1991.[2/] Thus, it is expected that transport energy demand elasticity will continue to be above one until the congestion has abated and until the urbanization factor reaches about 0.70.[3/] The elasticity will then decline to about 1.1 by 2005, and eventually to 1 by 2010. Total energy demand of the transport sector projected for the three periods based on these elasticities is 20,815 ktoe for 1998, 32,474 ktoe for 2005 and 43,191 ktoe for 2010. It is estimated that the share of energy consumption will increase to about 48% by 2010.

TABLE 2.4: THAILAND - Transport Fuels and Passenger-Miles Traveled (ktoe)

Petroleum Products/Passenger Miles	1982	1991	Annual Growth (%)
Regular Gasoline	919	1,430	5.0
Premium Gasoline	500	1,390	12.0
High Speed Diesel	1886	6,223	14.2
LPG	129	189	4.3
Total Fuels by Road Transport	3,434	9,232	11.6
Million Passenger Miles Traveled by Road Transport	12,815	28,600	9.3
Passenger Miles/TOE	3,732	3,098	-2.0
Miles/Gallon	11.3	9.3	-

Source: Thailand/Bank Mission.

2/ The urbanization factor for Taiwan, Singapore, Japan and US are 0.8, 1, 0.9 and 0.8 respectively.

3/ The US and Japan had an elasticity of 1.13 and 1.06 during 1960-1973. In fact, the elasticity for oil consumption in Japan was 1.4 during 1960-1973. The latter figure should be compared to Thailand's transport sector elasticity, since Thailand's transport sector uses oil exclusively.

2.11 ***Residential and Commercial Sectors.*** The growth of energy consumption in the residential and commercial (R&C) sectors averaged about 2.9% from 1986-1992 and its share declined from 32% to 23%. This decline was not unexpected since woodfuels were increasingly replaced with more efficient fuels, particularly LPG and electricity. Commercial use represents about 23% of the R&C sectors, and its share is increasing. The urban population represents about 20% of the residential sector, and its share is also increasing. About 90% of the energy consumed in the rural areas is woodfuel (mostly wood and charcoal). Table 2.5 provides the breakdown of energy consumption in residential and commercial sectors in 1991. Although the rate of rural electrification is very high (75%), wood continues to be the main cooking fuel in the countryside. The implied R&C elasticity during the 1986-1992 period, measured with respect to total GDP, is 0.28. While it is generally expected that energy demand elasticity in residential and commercial sectors decreases because space-related energy uses, such as heating, cooling and lighting, tend to saturate for a given building space in spite of continued growth, the elasticity value in Thailand (0.28) is unusually low.[4/] This value seldom falls below 0.3 because about one-third to one-fourth of the energy use, such as for electronic entertainment equipment, is basically income-rather than space-dependent. A possible explanation for such a low elasticity in the residential and commercial sectors could be the unreliability of data on consumption of woodfuels. Therefore, it is assumed the elasticity for R&C will be higher than the 0.28 and have estimated average elasticities of 0.57 for the three periods. Based on these elasticities, the projected energy consumption for the residential and commercial sectors is 9,567 ktoe in 1998, 12,437 ktoe in 2005, and 14,921 in 2010.

TABLE 2.5: THAILAND - 1991 Energy Consumption in Residential and Commercial Sectors
(ktoe)

Sector	LPG	Fuel Oil	Kerosene	Electricity	Fuelwood	Charcoal	Paddyhusk	Total
Urban areas	350	0	1	554	76	175	0	1,156
Rural areas	112	0	36	226	2,088	1,682	265	4,409
Total Residential	462	0	37	780	2,164	1,857	265	5,565
Commercial	391	22	9	1,222	0	0	0	1,644
Total Residential & Commercial	853	22	46	2,002	2,164	1,857	265	7,209

Source: Thailand/Bank Mission.

2.12 ***Agricultural Sector.*** Energy consumption in agriculture increased at an average of 5.4% from 1986-1992, while the sector's share remained almost constant, at 7%, and GDP elasticity of demand was about 1.6. However, the historical energy-GDP correlation in this sector has not been consistent:[5/] In part, this could be explained by the fluctuation in the export prices of agricultural products. Therefore, it is difficult to establish a meaningful elasticity based on available historical data. However, it is expected that elasticity will decline gradually, as in other countries. Given that the sector's energy share is only 7%, and that about 96% of the fuel used is high-speed diesel, energy consumption in this sector does not represent a major variable in total consumption. Based on the assumption that elasticity will decline to 0.90 by 2010, it is estimated the sector will need 2,464 ktoe in

4/ Countries with similar patterns of consumption have a much higher elasticity than Thailand: Malaysia has a residential and commercial sector elasticity of 1.1, Taiwan 0.97, the US and Japan 0.64 and 0.69.

5/ In 1990, energy consumption grew at 10%, while agricultural GDP registered a negative growth of 1.8%.

1998, 3,154 ktoe in 2005 and 3,612 ktoe in 2010.

2.13 Table 2.6 presents the forecast for final sectoral energy demand for 1993-2010. The aggregate GDP elasticities for the three planning periods decline from 0.88 to 0.84, and ultimately to 0.76 (see Annex 1 for details on projected GDP and energy consumption growth).

TABLE 2.6: THAILAND - Forecast for Final Sectoral Energy Demand for 1993-2010
(ktoe)

Sector	1991 a/	1992 b/	1993	1998	2005	2010
Industrial	9,533	10,382	11,089	15,415	22,813	28,510
Transport	11,910	12,696	13,786	20,815	32,474	43,191
Residential & Commercial	7,209	7,389	7,714	9,567	12,437	14,921
Agriculture	1,827	1,922	2,003	2,464	3,154	3,612
TOTAL	30,479	32,389	34,592	48,261	70,878	90,234
Implied Elasticity for Period	0.78	0.70	0.88	0.88	0.84	0.76
Average Annual Growth for Period				6.9%	5.6%	5.0%

Source: Bank Mission.
a/ Actual.
b/ Estimated.

2.14 The Bank forecast is different from the Government's in that it projects a higher share of energy consumption in the transport and industry sectors. Table 2.7, which presents the Government's projection, was constructed in a way so as to provide a basis for comparisons with Bank data. First, the years used by the Government are different and, therefore, the data have been adjusted. Second, since the Government data represent only commercial fuels, the Bank added non-commercial fuel consumption in order to arrive at total energy consumption. The result shows that the Bank's forecast with respect to overall sectoral energy demand is higher by 6%, 9% and 5% for 1998, 2005 and 2010, respectively. This is due to the Bank's higher projections for transport sector fuel (greater by 8%, 14% and 15% for 1998, 2005 and 2010), and for industrial sector fuel (higher by 12%, 11% and 1% for the same years): In the transport sector, high demand is expected to continue because of traffic congestion, high growth in the economy (transport fuels are income elastic) and the low level of urbanization (para. 2.10). In the industrial sector, the efficiency gain will not be as high nor as rapid as may have been projected by the Government.

TABLE 2.7: THAILAND-Government's Forecast for Final Sectoral Energy Demand for 1993-2010
(ktoe)

Sector	1991 a/	1996 a/	1998 b/	2001 a/	2005 b/	2010 b/	2011 a/
Industrial	6,022	9,088	10,390	12,700	16,841	24,383	26,278
Transport	11,832	17,258	19,362	23,003	28,572	37,997	40,260
Agri & Res & Commercial	4,638	6,728	7,552	8,982	11,114	14,664	15,480
Total Commercial	22,492	33,074	37,304	44,685	56,527	77,044	82,018
Non-Commercial	7,280		8,058		8,588	8,808	
TOTAL	29,772	33,074	45,362	44,685	65,115	85,852	82,018

Source: NEA, NEPO and TDRI.
a/ Government data.
b/ Bank adjustment of Government's data.

C. Power Demand

2.15 Forecasting power demand is the responsibility of the Load Forecasting Working Group (LFWG), composed of representatives of NEPO, EGAT, PEA, MEA and NEA. The latest power load forecast prepared by the LFWG, and used by EGAT for its 1992-2006 Power Development Plan (PDP), is summarized as follows (for EGAT's load, i.e., MEA, PEA and EGAT's direct consumers):

(a) Peak demand of 8,072 MW in 1991 is forecast to increase to 13,075 MW by 1996, an annual growth of 10.2% for the Seventh Plan. In comparison, the average annual growth for the 1987-1991 period was 14.1%.

(b) Energy load is forecast to increase from 49,600 GWh in 1991 to 81,741 GWh by 1996, an annual growth of 10.5%, which implies a slight improvement in the system's load factor.

(c) For the long-term, peak demand is estimated to reach 19,000 MW by 2001 and 25,515 MW by 2006, i.e., a decline of 7.8% and 6.1% for the 1996-2001 periods (Eighth Plan) and 2001-2006 (Ninth Plan), respectively. Energy load is expected to grow at slightly higher rates, thus continuing the improvement of the system's load factor.

2.16 EGAT's total generation requirements are presented in Table 2.8, which includes the Bank estimates for the 2006-2010 period.[6/] This forecast is characterized by a greater expansion in PEA's power market, where energy demand is expected to grow at 12% during the 1992-1996 period compared to MEA's growth of 9.6% for the same period.

6/ The forecast for 2006-2010 was based on the final year's (2006) growth rate for the direct customers of MEA, PEA and EGAT, subject to a ceiling load factor of 70%.

TABLE 2.8: THAILAND - EGAT's Total Generation Requirements (Including Station Service)

Year	Peak Demand		Energy Load			Annual Load Factor %
	(MW)	Increase %	Average (MW)	(GWh)	Increase%	
Historic						
1978	2,101		1,412	12,372		67.2
1979	2,255	7.4	1,594	13,965	12.9	70.7
1980	2,417	7.2	1,684	14,754	5.7	69.7
1981	2,589	7.1	1,822	15,960	8.2	70.4
1982	2,838	9.6	1,927	16,882	5.8	67.9
1983	3,204	12.9	2,177	19,066	12.9	67.9
1984	3,547	10.7	2,405	21,066	10.5	67.8
1985	3,878	9.3	2,666	23,357	10.9	68.7
1986	4,181	7.8	2,829	24,780	6.1	67.7
1987	4,734	13.2	3,218	28,193	13.8	68.0
1988	5,444	15.0	3,653	31,997	13.5	67.1
1989	6,233	14.5	4,162	36,457	13.9	66.8
1990	7,094	13.8	4,930	43,189	18.5	69.5
Forecast						
1991	8,072	13.8	5,662	49,600	14.8	70.1
1992	9,000	11.5	6,333	55,475	11.8	70.4
1993	9,924	10.3	7,002	61,339	10.6	70.6
1994	10,892	9.8	7,712	67,561	10.1	70.8
1995	11,946	9.7	8,507	74,522	10.3	71.2
1996	13,075	9.5	9,331	81,741	9.7	71.4
1997	14,205	8.6	10,195	89,307	9.3	71.8
1998	15,354	8.1	11,026	96,591	8.2	71.8
1999	16,531	7.7	11,921	104,431	8.1	72.1
2000	17,765	7.5	12,860	112,653	7.9	72.4
2001	19,000	7.0	13,822	121,083	7.5	72.7
2002	20,219	6.4	14,778	129,455	6.9	73.1
2003	21,482	6.2	15,790	138,322	6.8	73.5
2004	22,795	6.1	16,839	147,509	6.6	73.9
2005	24,150	5.9	17,938	157,137	6.5	74.3
2006	25,515	5.7	19,064	166,999	6.3	74.7
2007	26,960	5.7	20,201	176,959	6.0	74.9
2008	28,488	5.7	21,433	187,754	6.1	75.2
2009	30,103	5.7	22,691	198,774	5.9	75.4
2010	31,811	5.7	24,054	210,710	6.0	75.6

Source: EGAT and Bank estimates.

2.17 Power demand projections by consumer categories are presented in Table 2.9. It is expected that the three main consumer categories --industrial, commercial and residential-- will grow at similar rates throughout the planning period.

TABLE 2.9: THAILAND - Power Demand Growth by Sectors
(GWh)

Year	Residential	Commercial	Industrial	Other a/
1992	10,049	12,169	22,377	3,238
1996	14,794	19,245	32,700	4,116
2001	21,963	28,940	48,354	5,278
2006	31,018	39,811	67,172	6,432
Growth Rates				
1992-1996	10.2	12.1	9.9	6.2
1996-2001	8.2	8.5	8.1	5.1
2001-2006	7.1	6.6	6.8	4.0
1992-2006	8.4	8.8	8.2	5.0

Source: EGAT.
a/ Includes public utilities, government institutions, nonprofit organizations, agriculture pumping, street lighting and temporary users.

2.18 In general, LFWG's power demand projections appear to be quite sound and consistent with historical values and expected trends. Basic underlying assumptions are: (a) a gradual slowing of Thailand's economy, although growth will be sustained over the planning period, (b) a declining GDP elasticity of energy demand from 1.24 to 1.06 in 1992-1996, and (c) an improvement in the overall annual load factor from 70% to 75%. The last two factors imply a more efficient use of energy, explained by changes in the economy's structure and the gradual introduction of more efficient technology. Although there may still be some room for improving the power forecasting practice, the current forecast is considered appropriate for the purposes of the present study.

2.19 Although the methodology used relies heavily on an end-use approach --and as such, this approach does not directly address price variables-- resulting forecasts are implicitly based on price levels and structures that dominate during the period from which consumption indexes are extracted. In general, energy prices have remained at economic cost levels and will probably continue to do so. Therefore, it is safe to assume that EGAT's forecasts are consistent with current and future price levels. Future adjustments in price structures aimed at correcting existing relative price distortions, will tend to affect demand structure (e.g. the size of peak demand in power), although not demand volume. Changes in demand structure will affect capacity requirements and, hence, capital investment requirements. However, their impact on fuel options would be negligible since energy demand would tend to remain unchanged.

2.20 Future load forecasts should consider the following:

(a) LFWG's current forecasting methodology varies widely, from the application of a detailed end-use approach for residential consumption, to the use of surveys and electricity intensity indicators for industrial consumption and factor analyses for the commercial sector. Although these approaches are based on intensive data collection on a variety of parameters (such as the number and saturation of electricity appliances, dwelling types, demographic trends, commercial floorspace and industrial investment plans), which help explain how energy is used, they do not establish a direct nor clear link with economic conditions affecting this consumption. Income and price variables are not directly integrated to the load forecasting exercise; therefore, projections could

be largely misleading unless their consistency with micro and macroeconomic variables is assured. Although it is considered that in this particular case, the end-use approach does not create distortions, the Bank believes that electricity prices (both their level and structure), income levels and sector economic growth should be integrated into the load forecasting process.

(b) The current load forecast is too conservative in the treatment of demand side management (DSM) or any other energy conservation measures. In fact, although EGAT has an ongoing DSM pilot project which is expected to reduce peak demand by 250 MW (total potential of DSM measures may reach up to 10% or around 2,000 MW of peak demand by the next decade), this impact has not been considered in the 1991 forecast because, it is argued, experience is still required to assess its effectiveness in reducing load. This may be an excessively conservative approach since the uncertainties surrounding the DSM projects are similar to those associated with other long-term supply projects included in the Power Development Plan, (such as fuel costs and availability).

2.21 The forecasted increase in the system's annual load factor is neither clearly justified nor consistent with recent trends, which reveal a constant factor during the last 15 years. This issue should be re-examined in order to identify to what extent the load factor increase is subject to, or should be complemented by, the implementation of load management measures.

D. Demand by Type of Fuel

2.22 The various fuels consumed in 1991 are shown in Table 2.10. Since 1982, the share of imported coal increased by an average of about 7% per year, lignite by 16.6%, oil by 2%, natural gas by 1.2% and electricity by 11.5%.[7/] During the same period, the share of woodfuels decreased by 6% per year. The following paragraphs discuss the type of fuel needed to meet the sectoral energy demand identified in Section B of this chapter. The scenarios A, B and C refer to gas, LNG and imported coal, which are discussed in Chapter VI.

TABLE 2.10: THAILAND - Past Consumption by Type of Fuel
(ktoe)

Products	1982	Share %	1991	Share %	Annual Growth 1982-91 (%)
Oil	7,834	48	17,581	58	9.4
Natural Gas	0	0	360	1	-
Lignite	155	1	1,228	4	25.9
Coal	101	0.6	331	1.1	14.1
Electricity	1,281	8	3,698	12	12.5
Non-Commercial	6,850	42	7,281	24	0.7
TOTAL	16,221	100	30,479	100	7.3

Source: Thailand/Bank mission.

7/ The limited increase in the share of natural gas applies to its use in industry; in power generation, the share has been increasing significantly since 1982.

2.23 ***Non-Commercial Energy***. In 1991, about 24% of the final energy consumed in Thailand was non-commercial. Manufacturing consumed about 41% and the balance was by the residential sector. Table 2.11 shows the type of non-commercial energy used by sectors.

TABLE 2.11: THAILAND - Non-Commercial Energy Consumption - 1991
(ktoe)

Sub-Sectors	Total	Wood Fuel	Charcoal	Bagasse	Others
Industry					
Food and Beverages	2,753	NA	NA	NA	NA
Woods and Furniture	18	NA	NA	NA	NA
Chemical	87	NA	NA	NA	NA
Non-Metallic	118	NA	NA	NA	NA
Basic Metal	18	NA	NA	NA	NA
Total	2,994	628	-	1,968	398
Residential	4,286	2,164	1,857	-	265
Total Non-Commercial	7,280	2,792	1,857	1,968	663

Source: Thailand/Bank mission.

2.24 The use of non-commercial energy in manufacturing (92% of which is in the food and beverage industries), declined at an average of 4.7% per year from 1982-1991 and 6.6% from 1986-1991. This decline is expected to continue; thus, it is estimated that the share of non-commercial energy consumption in total manufacturing will drop from its current level of about 30% to 14% by 2010. Natural gas and LPG will be the major replacements. In the event that gas is not available, electricity will be the most likely alternative because non-commercial energy (bagasse and fuelwood) in the sector is mostly used in the form of indirect heat (for raising steam). To avoid contaminating food and beverages, any direct heat must be a clean-burning fuel such as gas, LPG, or preferably electricity. Therefore, while coal, lignite and oil may replace non-commercial fuels to produce steam for a while, the industry would eventually shift to gas, LPG or electricity, depending on their availability, price and end-use application. The choice of replacement fuel depends on the price of alternative fuels at a particular time.

2.25 The share of non-commercial energy (woodfuel and charcoal) in the residential and commercial sectors is also expected to decline from its present level of 57% to 34% under gas-dominating scenarios and to 41% in imported coal and LNG scenarios.[8/] During the past eight years, it has declined at an average rate of 7% per year. It is estimated that declines in the consumption of non-commercial energy will be compensated for by increase in the consumption of LPG and electricity, depending on the period, price and the distance of the rural communities from the gas processing plants and refineries. But the pace of electricity penetration into the residential sector may also be a function of the country's cooking habits. In general, in developing countries, kerosene is the first woodfuel replacement, followed by LPG, gas and electricity. In Thailand, however, this is not expected to occur. Kerosene usually substitutes for woodfuel when its price is subsidized; but in Thailand, its consumption has actually dropped (to less than 1% of total energy consumption) because the price is not subsidized. With regard to natural gas, residential use is not justified because there is no need for space

8/ This is because the price of electricity under imported coal and LNG-scenarios is more expensive than under the gas scenario; thus more woodfuels and charcoal would be used, with higher electricity prices.

heating and the unit cost of gas would be too high (making the construction of a gas network uneconomic). Thus, in the absence of gas and kerosene, LPG and electricity would replace woodfuels in the residential and commercial sectors until the subsidy on LPG is removed. At that time, the consumption of kerosene may increase again.

2.26 ***Industrial Fuels***. The use of different fuels in the industrial sector is more complicated. With respect to non-commercial energy, as discussed above, its use in industry is expected to decline to 13% by 2010. With respect to gas, current consumption is about 50 mmcfd, representing 6% of total gas consumption; and, although PTT projects that industrial gas consumption will increase to about 280 mmcfd by 1998 and 490 mmcfd by 2005, a more realistic projection would be about 280 mmcfd by 1998, 300 mmcfd by 2005 and 320 mmcfd by 2010. These figures are based on: (a) PTT's commitment to meet 100% of the present and future gas requirements of its existing customers who use gas for direct heat application --such as glass or ceramic factories, where gas substitutes for LPG and achieves a high netback value-- or who use it in industrial co-generation plants, where it yields the same economic value as in combined cycle power plants; and (b) PTT's identified future customers, who will use gas in those industrial applications which would yield a gas netback value equal to or greater than the gas use in a combined cycle power plant. Where gas and LNG are imported, industrial gas consumption could possibly increase to include those unidentified future customers whose need of gas falls within the above economically-based gas utilization criteria. Under the coal scenario, however, the use of gas would be limited to the above quantities. Moreover, even when more imported gas or LNG under these two scenarios will be available, the gas supply to industry should not increase during the third period (2005-2010) because the domestic gas supply will begin to decline (after 2005). Hence, it is assumed the supply of gas to industry will remain essentially flat during the second and third periods, for all three scenarios (gas, LNG and coal). This situation could change if the nuclear option is exercised or if there is a significant change in the relative price of fuels.

2.27 Regarding the choice among imported coal, lignite, fuel oil and electricity in the industrial sector, the decision in the study was based on the end-use application of the fuel, and its total economic costs which includes the cost of environmental mitigation measures. Most of the lignite currently used in industry is in cement plants. This trend is expected to continue because the study assumes that, as part of the air pollution control measures, all future major users of lignite would be equipped with flue gas desulphurization (FGD) units and that the existing ones will retrofit their plants to install FGDs. For other, smaller, industrial users of coal, it is more economic to use low-sulphur imported coal, rather than install FGD units. Hence, the share of lignite in the industrial fuels would be limited to only major users such as cement plants, and therefore would increase moderately, from its current level of 13% to about 16% by 2010. This increase is consistent with the growth of the existing and potential major users of lignite in Thailand.

2.28 Imported coal in industry met 3.5% of the sector's energy requirements in 1991, and included steam coal (192 ktoe), anthracite (14 ktoe), coke (56 ktoe) and other coals (69 ktoe). Since 1982, the share of imported coal grew from 2.1 % to 3.5%. The study assumed that under the gas scenario, when the price of electricity is cheaper, only the present industrial users of imported coal would continue to use it. However, under the imported coal and LNG scenarios (which raise electricity prices), industry's consumption of this coal will increase to compensate for the shortfall of gas (which slows the shift to electricity). The demand projection for electricity in industry was based on EGAT's forecast, which applies the end-use analyses and corresponds to the gas scenario. However, the study assumes that scenarios under which electricity is generated using imported coal or LNG would result in reduced consumption of electricity because the cost of electricity under these two scenarios is higher,

and the industrial sector usually exhibits a high price elasticity.

2.29 The choice of oil for the balance of industry's energy needs depends on the price and availability of low sulphur fuel oil (which forms the basis of this study) and the end-user preference and end-use technology. Table 2.12 shows the energy forecast (according to type of fuel) in the industrial sector.

TABLE 2.12: THAILAND - Projections of Energy Consumption in Industry by Type of Fuel
(ktoe)

Products	1991	1993	1998			2005			2010		
			A	B	C	A	B	C	A	B	C
Oil	2,932	3,412	3,663	3,663	3,663	6,981	6,981	6,981	9,019	9,019	9,019
	(31)	(30.9)	(23.5)	(23.5)	(23.5)	(30.5)	(30.5)	(30.5)	(31.4)	(31.4)	(31.4)
Natural Gas	360	592	2,484	2,484	2,484	2,652	2,652	2,652	2,785	2,785	2,785
	(3.8)	(5.3)	(16)	(16)	(16)	(12)	(12)	(12)	(10)	(10)	(10)
Lignite	1,228	1,450	2,130	2,130	2,130	3,420	3,420	3,420	4,580	4,580	4,580
	(13)	(13)	(14)	(14)	(14)	(15)	(15)	(15)	(16)	(16)	(16)
Coal	331	380	533	828	828	800	1,280	1,280	1,020	1,690	1,690
	(3.2)	(3.4)	(3.5)	(5.5)	(5.5)	(3.5)	(5.5)	(5.5)	(3.6)	(5.6)	(5.6)
Electricity	1,688	2,150	3,215	2,920	2,920	5,310	4,830	4,830	7,400	6,730	6,730
	(18)	(19.4)	(21)	(19)	(19)	(23)	(21)	(21)	(26)	(24)	(24)
Non-Commercial	2,994	3,105	3,390	3,390	3,390	3,650	3,650	3,650	3,706	3,706	3,706
	(31)	(28)	(22)	(22)	(22)	(16)	(16)	(16)	(13)	(13)	(13)
TOTAL	9,533	11,089	15,415	15,415	15,415	22,813	22,813	22,813	28,510	28,510	28,510
	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)

Source: Bank mission.
A: Gas-dominant scenario.
B: LNG-dominant scenario.
C: Imported coal-dominant scenario.

2.30 ***Transport and Agricultural Fuels***. The energy products used in the transport sector will continue to be oil-based, including LPG, gasoline, diesel, jet and aviation fuels, fuel oil and bunker. LPG, which currently accounts for less than 1% of the total energy consumed in transport, is used mainly by taxis. It is assumed that the LPG used in transport would be oil-based, and that the LPG derived from natural gas would be available for other uses (in reality, however, these two are interchangeable). The study also analyzed the use of compressed natural gas (CNG) in transport (para. 3.49) and concluded that given the high cost of domestic and imported gas in Thailand, the use of CNG in the country's transport sector would not occur on a large-scale basis. Therefore, the entire requirements for transport are projected under oil demand. With regard to agriculture, except for a very small amount of electricity (less than 1%), oil dominates as well, with diesel representing over 96% of the total. Therefore, fuel for this sector is also projected under oil demand.

2.31 ***Residential and Commercial Fuels***. As discussed in para. 2.25, while the use of non-commercial energy in the residential sector will decrease, the use of LPG and, to a lesser extent, electricity, will increase. The average growth of electricity consumption in the residential sector was about 13.8% from 1987-1991, the demand elasticity was 1.35, and it is estimated that electricity will

decline to 1.2 by 2010.[9/] The growth rate will slow to about 10% by 1998, 7.5% by 2005 and 6.5% by 2010, figures that are consistent with other countries' growth rates.[10/] Under the coal and LNG scenarios, because of the high cost of electricity, consumption of woodfuel and charcoal in the rural areas would not decline as rapidly as under the gas scenario (which produces cheaper electricity). Table 2.13 shows the projection for the various fuels needed in the residential and commercial sectors.

TABLE 2.13: THAILAND - Projections of Energy Consumption in Residential/Commercial Sectors by Type of Fuel
(ktoe)

Periods	1991	1993	1998			2005			2010		
			A	B	C	A	B	C	A	B	C
Oil	921	931	1,079	1,079	1,079	1,305	1,305	1,305	1,349	1,349	1,349
Electricity	2,002	2,417	3,820	3,494	3,494	6,194	5,474	5,474	8,470	7,426	7,426
Wood Fuel	2,164	2,183	2,334	2,497	2,497	2,469	2,829	2,829	2,551	3,073	3,073
Charcoal	2,122	2,183	2,334	2,497	2,497	2,469	2,829	2,829	2,551	3,073	3,073
TOTAL	7,209	7,714	9,567	9,567	9,567	12,437	12,437	12,437	14,921	14,921	14,921

Source: Bank Mission.
A: Gas-dominant scenario.
B: LNG-dominant scenario.
C: Imported coal-dominant scenario.

2.32 Table 2.14 shows the forecast of final energy consumption in various sectors according to type of fuel, as well as the share of individual fuels in total energy consumption. Also, it indicates that the change in the share of non-power fuels is relatively insignificant for different scenarios because the transport and agriculture sectors represent about 60% of total energy requirements.

9/ This pattern is consistent with that of Taiwan (1.08), Japan (1.16), the US (0.95) and Korea (0.97).

10/ The electricity growth rate in Korea is 9%, Singapore 7.5%, Japan 5% and the US 4%.

TABLE 2.14: THAILAND - Final Energy Consumption by Type of Fuel
(ktoe)

Products	1991	1993	Share (%)	1998 A	Share (%)	1998 B&C	Share (%)	2005 A	Share (%)	2005 B&C	Share (%)	2010 A	Share (%)	2010 B&C	Share (%)
Gas	360	592	1.7	2484	5.1	2484	5.1	2652	3.7	2652	3.7	2785	3.1	2785	3.1
Oil															
Industry	2932	3412	9.9	3663	7.6	3663	7.6	6981	9.8	6981	9.8	9019	10.0	9019	10.0
Agri	1827	2003	5.8	2464	5.1	2464	5.1	3154	4.4	3154	4.4	3612	4.0	3612	4.0
Trans	11910	13786	39.9	20815	43.1	20815	43.1	32474	45.8	32474	45.8	43191	47.9	43191	47.9
Res/Com	921	931	2.7	1079	2.2	1079	2.2	1305	1.8	1305	1.8	1349	1.5	1349	1.5
Total Oil	17590	20132	58.2	28021	58.1	28021	58.1	43914	62.0	43914	62.0	57171	63.4	57171	63.4
Imported Coal	331	380	1.1	533	1.1	828	1.7	800	1.1	1280	1.8	1020	1.1	1690	1.9
Lignite	1228	1450	4.2	2130	4.4	2130	4.4	3420	4.8	3420	4.8	4580	5.1	4580	5.1
Non-Commercial															
Industry	2994	3105	9.0	3390	7.0	3390	7.0	3650	5.1	3650	5.1	3706	4.1	3706	4.1
Res/Com	4286	4366	12.6	4668	10.3	4994	10.3	4938	7.0	5658	8.0	5102	5.7	6146	6.8
Total Non-Commercial	7280	7471	21.6	8058	16.7	8384	17.4	8588	12.1	9308	13.1	8808	9.8	9852	10.9
Total Non-power Final Demand	26789	30025	86.8	41226	85.4	41847	86.7	59374	83.8	60574	85.5	74364	82.4	76078	84.3
Electricity															
Industry	1688	2150	6.2	3215	6.7	2920	6.1	5310	7.5	4830	6.8	7400	8.2	6730	7.5
Res/Com	2002	2417	7.0	3820	7.9	3494	7.2	6194	8.7	5474	7.7	8470	9.4	7426	8.2
Total Electricity	3690	4567	13.2	7035	14.6	6414	13.3	11504	16.2	10304	14.5	15870	17.6	14156	15.7
TOTAL	30479	34592	100	48261	100	48261	100	70878	100	70878	100	90234	100	90234	100

Source: Bank mission.

E. Prices

2.33 The effect of energy prices on various fuel supply options was assessed with respect to two criteria: (a) the economic cost and value of individual fuels in different sectors and periods and (b) the absolute and relative levels of domestic prices of energy products in Thailand.

2.34 ***Economic Costs and Values of Fuels.*** The current prices of all energy products in Thailand reflect their actual economic costs except for lignite (para. 3.32). For the purpose of this study, the economic costs and values of all energy products were either related to international prices (for tradable commodities), or to their economic costs (for non-tradable commodities). The following briefly describes the basis for determining the economic costs and values of major fuels. Annex 2 provides the actual economic costs used for different fuels in the study from 1993-2010.

(a) The economic costs of imported gas, from Myanmar and Malaysia, are assumed to be the border price. The sellers' minimum border price is estimated to include the

depletion premium in the respective countries (see para. 6.6), as well as the operating and investment costs of gas development, production and transmission to the Thai border. Given that Malaysia and Myanmar have a gas reserve (to production ratio) which is less than 40-50 years,[11/] the value which both countries allocate to their gas (vis-a-vis Thailand) is expected to be the economic value of gas in the country's major consuming center (assumed to be Bangkok) minus the transportation costs to the border. This reflects the maximum border price the sellers expect. Since the final negotiated price will lie somewhere between this minimum and maximum price, the analysis provides a scenario for each. The economic cost of domestic gas was estimated to include gas development, as well as production and transportation costs from two major fields in the Gulf of Thailand (Erawan and Bongkot) to Bangkok. The future price of imported and domestic gas was assumed to increase according to changes in the international price of fuel oil and domestic and international inflation weighted in equal parts (about 1% per year).

(b) LNG's economic cost was assumed to be an average of the current CIF prices when sold in the Asian market (para. 3.44) plus regasification (including terminal) costs and the cost of transmission to Bangkok. LNG future prices are assumed to follow the indexation set for Japan's LNG price, which is linked to spot prices of crude oil.

(c) Because of an inherent thermal efficiency gain, gas has its highest value when used as a fuel in a combined-cycle power plant but, it is even higher when it substitutes for LPG in the industrial sector.[12/] Therefore, the economic value of domestic and imported gas as well as LNG is assumed to be the gas net-back value either at the gate of the industrial plant where it substitutes for LPG or when used for cogeneration, and/or at an economic-sized (600 MW) combined-cycle power plant located near Bangkok, assuming the gas or LNG would substitute for a notional imported coal-based power plant.

(d) Given that Thailand's lignite can not be exported because of its inferior quality (high sulphur and ash content, calorific value of 2500 Kcal per kg), the economic cost used for lignite is assumed to be EGAT's implied production cost or internal transfer price (about US$13 per ton) plus a depletion premium (para. 3.32).

2.35 ***Domestic Prices.*** The domestic price of energy products affects the fuel supply options in two ways: (a) at the absolute level, appropriate prices for energy products can discourage excessive energy consumption and (b) at the relative level, the price of individual products can be set in such a way so as to avoid distortions that lead to a pattern of consumption away from the least-cost fuel mix. Annex 3 provides the domestic fuel prices in Thailand.

11/ It is assumed that countries with reserves to production ratios of above 50 years are gas surplus countries, and below this ratio are "window" or gas deficit countries.

12/ The non-energy use of gas, such as for petrochemical plants, is not considered here because the feedstocks for petrochemical plants in Thailand are liquid gas such as ethane, propane and butane.

2.36 Oil Prices. In August 1991, the Government deregulated the price of all petroleum products except LPG. In addition, the Oil Fund, whose previous use sent erratic and contradictory signals to consumers, was gradually phased out. Currently, the ex-refinery prices are tied to the world market through periodic price adjustments based on the Singapore spot-market price. Except for a small surcharge levied on imported oil products to protect the domestic refiners, the domestically-refined petroleum price structure at the absolute level fully reflects the cost of supply based on the international market. The price of imported products also reflects the price of corresponding products in the international market. Thus, at the absolute level, the prices of oil and petroleum products are appropriately structured.[13/] Regarding relative prices, after deregulation, the difference in the effective tax rates of individual products was adjusted. As the result, excessive consumption of products such as kerosene diminished and the share of kerosene consumption in total petroleum products declined from 15% in 1982 to less than half a percent in 1991. Further, diesel prices have moved up relative to gasoline prices in response to the high demand for diesel oil. But, its price is still lower than that of gasoline; since 25% of diesel is consumed by non-transport users, they are not subject to road-use charges. Hence, the tax on diesel is relatively lower than on gasoline. Therefore, the relative price structure of petroleum products is also appropriately structured and will not have a distortionary effect on the various supply options considered in the study.

2.37 Gas Prices. The unique features of the domestic gas industry in Thailand have led to the development of a relatively sophisticated pricing structure in which the country has a separate pricing system for gas producers and consumers. As there are no direct sales of gas between producers and consumers, the Petroleum Authority of Thailand (PTT) is responsible for gas transmission, processing and distribution.

2.38 The cost of producing gas in Thailand is relatively expensive compared to neighboring countries such as Malaysia or Indonesia. This is due to the gas fields' complex geological features which result in the well-head transfer price bearing the high cost of field development and production. At present, only one major gas producer, Unocal, has been producing offshore gas in the Gulf of Thailand (since 1981). By the end of 1993, Total Company will also produce offshore gas from the Bongkot field (in the Gulf). While the gas sales-purchase contracts between PTT and Unocal and between PTT and Total are different --in fact, there are three separate contracts between PTT and Unocal for different areas-- the principles of producer-pricing structures are essentially the same: (a) the transfer price is based on the economic cost of supply; (b) the price is tied to the replacement of alternative fuels; (c) prices include indices reflecting domestic and international inflation; (d) prices include a "floor" and "ceiling" level to protect sellers and buyers and (e) prices are adjusted annually, except with devaluations when adjustments are immediate. The gas pricing structure for the Namphong field, which produces a relatively small amount of the dry gas used in the adjacent power plant, is somewhat different because of specific development costs and the composition of the gas (all methane). The average well-head price for Unocal's gas ranges from US$1.77 per mmbtu to US$2.08 per mmbtu, for Namphong gas, it is about US$1 per mmbtu and for Bongkot gas, it ranges from US$1.98 to US$2.25 per mmbtu. The structure of the producers' gas prices is consistent with international norms.

13/ At the absolute level, the price of energy products as a whole has been declining in real terms, because of the decline in the international price of oil products.

2.39 The principle the Government applies when setting consumer prices is to link gas prices to alternative fuel prices in each activity. The present price of gas to industry, which consumes less than 6% of the total, is intended to encourage LPG consumers to shift to gas; but, no such incentive is provided to fuel oil users, because gas has a lower netback value when substituted for fuel oil. The price to industry is significantly higher than the one established for the power sector, since the margin of substitution between LPG and gas has been high, even after a discount to allow for penetration of gas into the LPG market. The price to the power sector --where over 90% of total gas is used-- was previously set by the Government. However, two years ago, an agreement was signed between PTT and EGAT which set the price based on (a) the price paid by PTT to upstream producers (well-head price); (b) the average cost of gas transmission and (c) the value-added tax. The current average price of gas sold by PTT to EGAT is about 70 Baht per mmbtu. Now, PTT and EGAT are involved in a study which would establish a long-term pricing formula for future gas supply that is in line with international standards. The pricing system will create two separate contracts --one for the "firm" gas supply and one for the "interruptible." A daily quantity will be defined for the Firm supply (about 500 mmcfd), to fuel EGAT's combined-cycle power plants and the contract will be a take-or-pay type agreement. The price of the Firm contract will be equal to the pipeline cost of transporting the gas, plus the gas commodity price, which is equal to PTT's volume-weighted average purchase cost. The cost of an Interruptible contract will be based on the cost of alternative fuel and negotiated by the parties. The new price mechanism was approved by the Government on August 17, 1992.

2.40 Power Tariffs. In the power sub-sector, the structure of electricity tariffs has also been improved through gradual introduction of time-of-day use for major consumers, and certain corrections to relative prices by consumer categories. Nevertheless, there are still some distortions in the tariff system; namely, the tariff structure to distribution companies is inadequate and cross-subsidies among consumer groups and regions persist.

2.41 Distribution companies do not pay a demand charge to EGAT since their tariff structure is limited to an energy charge for bulk energy; i.e., their tariff structure has no provision for separating fixed costs, which are usually an important component in power generation and transmission. This distortion could have a negative impact on the overall efficiency of the power system. These companies are directly responsible for imposing time-of-day tariffs on major consumers, a policy aimed at improving the system's load factor (a measure of the degree of utilization of its capacity) in order to reduce the capital needed for expansions. However, lacking a demand charge, which would reward peak shaving and, conversely, penalize a less efficient use of the system's capacity, distribution companies have no incentive to improve the load factor. Thus, corrective measures should be taken through a cost-based tariff structure, which would include a demand charge, preferably under a time-of-day criteria, as well as energy charges.

2.42 Electricity tariffs to final consumers are uniform throughout the country. However, the bulk energy tariffs charged by EGAT differ among the regions. While MEA's average tariff is Baht 1.47 per kWh, PEA's tariff is 34% lower (Baht 0.96 per kWh). This direct subsidy by MEA in favor of PEA does not appear to affect its finances because MEA enjoys the benefit of lower distribution costs --related to economies of scale-- and a more attractive market. In fact, for the same tariff level and structure, MEA's average revenue is 10% higher than PEA's (see Table 2.15).

TABLE 2.15: THAILAND - Electricity Tariffs Indices for 1981 and 1991
(100: Average MEA tariff for each year)

Sector	MEA Tariffs		Outside MEA	
	1981	1991	1981	1991
Residential	1.000	1.006	0.831	0.777
Commercial	1.153	1.100	1.124	1.072
Industry	0.915	0.889	0.938	0.872
Agriculture	-	-	0.600	0.656
Others	-	-	1.542	1.411
Total	1.000	1.000	0.938	0.906

Source: Department of Energy Affairs, Ministry of Science, Technology and Environment.

2.43 Table 2.15 also presents the evolution of relative tariffs (or average revenues) during the 1981-1991 period. Although it can be observed that the 1991 structure appears more consistent with relative costs (as industrial and commercial tariffs decreased while those in agriculture increased), it appears that the current structure still keeps some cross-subsidies from industrial consumers to the residential and agriculture sectors.

2.44 Over the same period, average electricity tariffs gradually declined in real terms, reflecting the decline in the international price of fuel. Since early 1992, power tariffs have been set at the long-run marginal cost (LRMC) level and are expected to remain at this level in the long term.

CHAPTER III

Energy Supply

A. Fuel Options

Hydrocarbons

3.1 *Geology*. Oil and gas exploration and development activities in Thailand have been extensive enough to conclude that the area has gas resources but relatively minor oil potential. The country's total hydrocarbon resource base is spread over at least eight different geological structures, offshore and onshore. In the offshore areas, the most significant hydrocarbon resources to date have been found in (a) the Pattani Basin, which extends through the middle of the Gulf of Thailand and includes all the currently producing Unocal fields and (b) the Malay Basin, which extends from Malaysian waters into the Gulf of Thailand and includes the Bongkot structure, the largest known existing gas field in the Gulf. In the onshore areas, hydrocarbon potential is believed to exist in the northeast (in the Khorat Basin), and in the central-west areas (in the Phitsanulok Basin), where Shell's small Sirikit oil field is situated.

3.2 Other countries in the region have varying levels of potential resources. Although Cambodia and Vietnam have explored their offshore areas in the central Gulf of Thailand only minimally, these are potentially productive areas and like those in Thailand have small individual reservoirs and high unit costs of production. The northern offshore Malaysia peninsular is also similar: Substantial reserves of oil and gas have been found there, with gas predominant in the vicinity of the Thai border. However, these reservoirs appear to be more widespread and have less intensive structuring, which results in larger individual reservoir traps and therefore marginally lower unit costs of production. The offshore Andaman Sea has only been lightly explored: One sizeable gas field has been found there, southwest of Myanmar. Several other non-commercial discoveries have also been made offshore Myanmar. These developments indicate good potential for the Thai portion of the Andaman Sea, as well. Annex 4 provides a detailed description of Thailand's petroleum geology.

3.3 Although the potential for hydrocarbon resources in Thailand exists, the prevailing geology in the basins indicates that further development will not be easy: Due to the erratic deposit of fluvial reservoirs and complex structuring during deposition, the hydrocarbons are trapped in numerous small reservoirs that need sophisticated drilling and recovery techniques. Further, the small size of many fields and the rapid reservoir depletion create the need for a large number of offshore platforms, which, in turn, lead to high development and production costs. In a number of cases, the long lead time and additional costs have made field development uneconomic.

3.4 Most of the discoveries from work in the existing basins have been non-associated gas deposits, which have been rich in heavier hydrocarbons, including ethane, propane and natural gas liquids (NGL).

3.5 Because of the predominance of gas, and given the minor role of oil in Thailand's domestic hydrocarbon resources, the discussion in this study will be confined to the gas subsector.

However, the data for reserves and production include the condensate and oil, and the calculation of economic costs and values take into account the costs and benefits associated with their production.

3.6 ***Exploration***. Exploration for hydrocarbon began in Thailand about 1971 after the Government established the Petroleum Law. This outlined the guidelines for awarding concessions (which would be licensed to foreign companies through competitive bidding), and the Government's fiscal terms regarding taxes and royalties on hydrocarbon production in the contracted acreage. The Government's aim was to stimulate greater foreign participation in exploration and production activities, in light of the limited domestic capabilities in the area. Under the concession agreement, licensees had the right to explore for, produce, store, transport and sell petroleum. However, the Government had the first right to purchase any petroleum produced from the blocks.

3.7 The contractual terms established in the Petroleum Law have been amended on several occasions. In particular, significant revisions were made with respect to the fiscal regimes for new concession agreements in 1982 and 1989. As a result, the concessionaires who currently operate in Thailand are not bound to the same contractual terms. Three distinct contracts exist --Thailand I, Thailand II and Thailand III. The terms of Thailand II were not attractive to foreign contractors. In 1989, the Government recognized it needed to increase the domestic hydrocarbon supply to satisfy Thailand's rapidly growing demand and established a more relaxed fiscal scheme for newly awarded concessions. The Thailand III terms, which applied to all new onshore and offshore field developments, included a provision allowing the oil companies that had signed concession agreements under the Thailand II terms to change to the more lenient fiscal regime. [1/]

3.8 Under these contracts, exploration blocks are offered as concessions in formal licensing rounds and are structured according to a tax-royalty scheme, with the concessionaires taking an equity share in any hydrocarbon production from their blocks. In the most recent, the thirteenth licensing round in 1991, 104 concessions were offered. The results of the thirteenth round were somewhat disappointing, because only 33 blocks were awarded to a total of 17 different companies. By the end of 1991, 22 contracts had been signed for these recently awarded blocks.

3.9 The key terms associated with exploration and production in the concessions are: (a) time frames involve a six-year exploration period and a 20-year production period (for potential discoveries); (b) the maximum acreage held by any one company should not exceed 20,000 km square; and (c) the Government's take would include a royalty of 5%-15% (depending on the level of production), a special remuneratory benefit and a 50% tax on profits. The deduction allowed before taxes includes royalties, special remuneratory benefits, operating costs, depreciations, and any losses carried forward (not to exceed 10 years). The most recent round also included a provision requiring that any foreign oil companies awarded exploration contracts had to be incorporated in Thailand, with a minimum equity investment of US$4 million.[2/]

1/ Although the Thailand III terms were substantially better than those of Thailand II, they were not quite as favorable as the fiscal regime in Thailand I. As a result, all the companies that originally agreed to terms under the Thailand I regime had no incentive to switch to Thailand III.

2/ It appears the Government established this requirement with three objectives: (a) it wants to attract companies that intend to stay after discovery, rather than those which intend to extract profits and then "farm out" the discovery; (b) in case of litigation, it could claim an amount at least equal to registered capital; and (c) the case would be tried in Thailand in accordance with Thai laws.

3.10 It is particularly important for Thailand to find ways to motivate greater private sector participation due to the country's need for gas, the high costs associated with developing it and the significant economic value it offers. Despite the fact that companies perceive the climate in Thailand to be favorable, some exploration firms are reluctant to invest there, due to the fiscal regime, contractual terms and the country's potential for gas, relative to oil. The disappointing result of the thirteenth round clearly indicates that Thailand needs to improve its fiscal and contractual terms in order to attract foreign investors. For example, the requirements that the contractors incorporate a Thai company with US$4 million minimum capitalization has caused some concern among small investors, who are wary of the upfront costs. The larger firms are concerned that potential litigations could be tried under the Thai laws. The Government must consider ways to provide incentives to encourage private operators to invest for an intensive exploration program. Accelerating the exploration activities is essential, because despite the high cost of domestic gas, it is still less expensive than either imported gas or LNG. In this regard, two actions are recommended: (a) the Government should revise the existing fiscal regime and develop a new legal framework which would be more responsive to increased investment in gas exploration by private sector; and (b) it should strengthen the Department of Mineral Resources (DMR) at least in two key areas. The first would be to assess reserves, classifying them on a consistent basis and according to internationally accepted norms. The second would be to make an economic evaluation of hydrocarbon resources in order to establish a correlation between the costs and values of petroleum in Thailand's economy, and the prevailing fiscal regimes and contractual terms.

3.11 ***Reserves***. As discussed above, due to the complex geology, calculations of Thai reserves (prior to production history) were based on statistical occurrence rather than measured quantities. In essence, when statistical methods are used, the distinction between the proven and probable reserves becomes less definable, with proven reserves being somewhat less assured and probable reserves being somewhat more probable than indicated by the American Petroleum Institute (API). The basis for the data on reserves are the official DMR reports, which, in turn, are compiled primarily from the latest reserves data submitted by each company that has made discoveries. Annex 5 provides a more detailed discussion of the reserves' data.

3.12 Different reserves categories include the "proven," "probable," "possible" and "identified potential" (see Annex 5). Consistent with the practice of DMR, the probable reserves have been reduced by 40% (i.e., risked by 40%), and then reclassified as proven. Hence, the reserves under the "firm" scenario consist of proven reserves and 60% of the probable reserves. Possible reserves, which includes the remaining 40% of the probable reserves, are reduced by 70%, and then added to the "firm" reserve scenario to obtain the "most likely" reserve scenario. Quantities under the "high" reserve scenario include the "firm" reserves plus 50% of possible and identified potential reserves. The "identified potential" is the estimate of expected reserves from (a) those discoveries to which no possible reserves have been assigned and (b) mapped but undrilled prospects analogous to and associated with discovered fields. In these analyses, no provision is made for unmapped prospects in existing producing areas or new areas with undetermined potential.

3.13 At present, about 377 million barrels (mmbbl) of oil and condensate and about 8,413 bcf of natural gas have been found in Thailand's onshore and offshore basins. From this, about 245 mmbbl of liquids and 6,455 bcf of gas remain to be produced. In addition to possible and unidentified potential reserves in the production basins, some unidentified potential also exists in the Andaman Sea and the onshore Khorat Basin. However, under current economics and technology, these reserves are speculative. Since most areas appear to have gas potential, market availability, infrastructure, and

favorable domestic gas pricing are essential in order to provide incentives for exploration and development. Table 3.1 below shows the hydrocarbon reserves of Thailand at the end of 1992.

TABLE 3.1: THAILAND - Hydrocarbon Reserves as of December 31, 1992

	Rem. Proven		Rem. Risked Prob.		Total Firm		Most Likely		High	
Petroleum	mmbbl	bcf	mmbbl	bcf	mmbbl	bcf	mmbbl	bcf	mmbbl	bcf
Offshore										
Condensate/Oil	144	-	33	-	177	-	348	-	556	-
Gas	-	4,585	-	1,250	-	5,835	-	10,192	-	16,549
Onshore										
Condensate/Oil	46	-	22	-	68	-	90	-	153	-
Gas	-	462	-	158	-	620	-	770	-	868
Total Thai										
Condensate/Oil	190	-	55	-	245	-	438	-	709	-
Gas	-	5,047	-	1,408	-	6,455	-	10,962	-	17,417

Source: DMR, PTT and Bank mission.

3.14 ***Production***. Except for minor oil production by the Defense Department in Fang Basin (the northernmost part of the country) in the 1960s, commercial production of hydrocarbon began in 1981 by Unocal at the offshore Erawan field. This was followed in 1983 with the production of Thai Shell's onshore Sirikit oil field. Table 3.2 lists the production by major fields since 1981.

TABLE 3.2: THAILAND - Past Production of Hydrocarbon

Gas: mmcfd Condensate/Oil: 1,000 bpd

Fields	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992 a/
Unocal I (Erawan)												
Gas	29	129	148	186	185	162	209	217	221	231	277	250
Cond.	1	6	6	7	7	7	6	6	7	8	10	9
Unocal II (Baanpot, Satun, Platong, Kaphong)												
Gas	-	-	3	31	151	159	249	333	325	337	417	350
Cond.	-	-	0	2	7	8	9	12	11	11	12	10
Unocal III (Funan, Jakrawan, Gomin)												
Gas	-	-	-	-	-	-	-	-	-	-	0	151
Cond.	-	-	-	-	-	-	-	-	-	-	0	8
Thai Shell (Sirikit)												
Gas	-	-	5	17	28	29	31	30	32	41	42	45
Oil	-	-	6	14	21	20	17	18	20	23	23	22
Esso (Namphong)												
Gas	-	-	-	-	-	-	-	-	-	0	38	57
Total Major Fields												
Gas	29	129	156	234	364	350	489	580	578	609	774	853
Cond	1	6	6	9	14	15	15	18	18	19	22	27
Oil	-	-	6	14	21	20	17	18	20	23	23	22

Source: DMR, PTT and Bank mission estimate.
a/ = estimated as data not compiled by 2/10/93.

3.15 As shown in Table 3.2, over the past 12 years, hydrocarbon production increased from 1,000 bpd of petroleum liquids and 29 mmcfd of gas, to 49,000 bpd of liquids and 853 mmcfd of gas. Production is expected to increase further. The Bongkot gas field will come on stream by early 1994, initially adding about 150 mmcfd to the country's gas supply, and eventually reaching a production plateau of 300 mmcfd. The project is under construction and a gas sales-purchase agreement has been signed between the gas producers (PTTEP, Total) and the purchaser (PTT). About 100-120 mmcfd of this gas will be transported to Khanom for use in power generation, and the balance will be transported through the existing pipeline to Rayong for use in power and industry. The present gas supply of Unocal fields, about 700 mmcfd, is transported to the Rayong through an existing 34" diameter pipeline, connecting the Erawan offshore platform in the Gulf of Thailand to Rayong (a 430 km. offshore pipeline). The Second Gas Pipeline Project, which runs parallel to the existing one, is under preparation and scheduled to be completed by the end of 1996, at which time it will provide an additional transport capacity of about 800 mmcfd. Unocal is in the process of concluding its fourth gas sales-purchase agreement with PTT for an additional supply of gas from fields under its contract III, to be transported through the proposed second pipeline.

3.16 The forecast for domestic gas supply represents realistic scenarios since future production will come mostly from the offshore fields of Unocal, Bongkot, Field 12/27 and Maersk (see Table 3.3). Unocal fields have a long history of production (12 years), and, projections can, therefore, be made with reasonable accuracy. The Bongkot field, although not yet in production, has been subject to extensive appraisal drilling (23 wells); therefore, the information available is sufficient to establish a reasonable forecast for this field as well. In addition, a detailed evaluation of potential reserves and production of Unocal and Bongkot fields has been conducted by qualified consultants in connection with issuance of reserves certification and confirmation required for the Bongkot and Second Gas Transmission projects. Therefore, reserves and production data for these two fields, which together represent over 80% of total future supply, are considered highly reliable. Assumptions about development and production forecasts of other fields are discussed in Annex 5.

TABLE 3.3: THAILAND - Hydrocarbon Production Forecast

Gas: mmcfd Liquids (Condensate/Oil): 1,000 bpd

	1993		1998		2005		2010	
	Most Likely	High	Most Likely	High	Most Likely	High	Most Likely	High
Domestic								
Gas								
Offshore	850	850	1,200	1,400	1,350	2,150	685	1,500
Onshore	107	107	107	107	58	79	29	68
Liquids								
Offshore	47	67	51	72	44	77	13	40
Onshore	21	21	16	29	3	12	2	5
Total Domestic								
Gas	957	957	1,307	1,507	1,408	2,229	714	1,568
Liquids	68	88	67	101	47	89	15	45
Import								
Gas	--	--	300	300	300	650	300	650
Total Domestic & Import Gas	957	957	1,607	1,807	1,708	2,879	1,014	2,218

Source: PTT and Bank mission estimate.

3.17 The average economic cost of developing and producing domestic gas in the Gulf of Thailand and transporting it to Bangkok is estimated to be US$2.00 per mmbtu. Average costs were calculated based on a weighted average of gas production in Unocal fields and in the Bongkot field. Annex 6 provides the analysis and assumptions used for calculating the costs of the domestic gas supply.

3.18 ***Gas Imports***. Given the country's limited gas supply, Thailand has often considered the possibility of importing gas from the neighboring countries of Malaysia, Myanmar and, recently, Vietnam. While discussions with Malaysia and Myanmar have occasionally led to the various governments announcing final gas sales-purchase agreements, to date no agreements have been signed. The reasons for the lack of progress and protracted negotiations in each case are different.

3.19 Myanmar. Myanmar could provide a potential source of gas supply for Thailand because its offshore gas discovery in the Gulf of Martaban is estimated to contain 3-5 TCF of gas reserves (based on the limited drilling results in the area to date). The field was discovered by JAPEX in 1982 and it has two known structures, 3D-A and 3C-A, which are located off the country's southern coast, approximately 100 miles from Yangon. TOTAL company of France is now carrying out preliminary appraisal and development (including 3-D seismic and 3-5 delineation wells) which are expected to be completed by mid-1994. Full-scale development should follow immediately and it is estimated this will include four well-platforms, one central processing platform, and 20 development wells. While three possible routes are being studied to pipe gas to Thailand, for the purpose of this study, the one most commonly mentioned, through the Three Pagados Pass, was analyzed. This will involve a 325 km. underwater pipeline from the offshore gas field to a landing point in Myanmar (Amherst), and a 100 km. onshore pipeline from the landing point through the eastern region of Myanmar, to the Thai border near the Three Pagados Pass. An additional onshore pipeline of about 330 km. from the Thai border to Bangkok will be required to transport the gas to the consuming centers around the Bangkok area. Thus, the total pipeline will be about 755 km. The system is also envisaged to include a spur line (about a 120 km. length) to south Yangon, to supply a portion of the gas to that market. While Martaban field reserves are still considered speculative, they are expected to be 3-5 tcf. This study considers a "most likely" field size to be 3.5 tcf producing at a plateau rate of about 400 mmcfd (300 mmcfd to Thailand and 100 mmcfd to Myanmar). The possible field size of Martaban is assumed to be 5 tcf, producing at a "high" plateau rate of 625 mmcfd (500 mmcfd to Thailand and 125 mmcfd to Myanmar). TOTAL's preliminary cost estimates include US$380 million for exploration, development and production and about US$700 million for the pipeline to Bangkok. In addition, the estimated cost of a spur line to Yangon for domestic supply is US$120 million. The costs estimated by Total appear to be low, and it is therefore assumed that project costs will be about US$1.57 billion, which include US$550 million for development and production, US$900 million for the pipeline and US$120 for the spurline. Based on this cost estimate and the assumption that gas delivery to Bangkok will begin in early 1998 at the rate of 300 mmcfd and remain at that level during the project life (20 years), the delivered cost would be US$1.69 per mmbtu to the Thai border, and US$2.26 per mmbtu to the Rachaburi power station in Bangkok.[3/] These costs do not include any depletion premium for Myanmar (para. 6.6). For the "high" gas scenario (500 mmcfd), the corresponding values are US$1.31 per mmbtu at the Thai border, and US$1.75 per mmbtu at Bangkok. Annex 6 provides the basis of these analyses and the assumptions.

3/ The heating value of Myanmar gas is assumed to be 1,000 btu per cubic feet.

3.20 The pace of negotiations between Thailand and Myanmar until recently had been very slow. This was due to combination of factors, including the uncertainties associated with the size of reserves, the financing and feasibility of the project in light of Myanmar's current political situation, and potential alternative uses for gas. Also, Thailand considers the purchase of gas from Myanmar to be contingent on its active participation in the upstream operation of the Martaban gas fields, mainly to exercise a degree of control over gas production and supply. Myanmar, however, does not favor such involvement. Lately, however, the pace has picked up because Myanmar took an important step by awarding Total a contract for developing the field and operating it afterwards. More important, PTTEP, the upstream arm of PTT, has signed a production-sharing contract with Total, acquiring a 30% share. Based on these actions and a relatively better economic situation for Myanmar gas as compared to Malaysia's, it is expected that the gas import from Myanmar will soon materialize. Thus, it is assumed that under a "most likely" scenario, gas import from Myanmar will begin early in 1998 at 300 mmcfd and stay at that level; but, under a "high" gas scenario, the supply would increase to 500 mmcfd after 2005.

3.21 Malaysia. Gas reserves in the Malaysian offshore portion of the Malay Basin (which could be exported to Thailand) are quite large, about 27.5 tcf. Approximately 7.5 tcf of this is produced along with oil, and therefore has a clear market priority because it would otherwise be flared. The remaining 20 tcf, which could be produced at the rate of 2,500 mmcfd, is currently underutilized. Recently, the Jerneh field, one of the largest gas fields offshore the Malaysian peninsula, was placed in production at the rate of 150 mmcfd and the operator (Esso) plans to increase this to 750 mmcfd by the year 2000. Current demand in peninsular Malaysia is about 500 mmcfd (350 mmcfd domestic and 150 mmcfd exported to Singapore). This demand is expected to grow to around 1,300 mmcfd by the year 2000, which includes the Singapore export. Thus, Malaysia has basically three options toward this gas. It can (a) keep the resources underground for future domestic use, projected by year 2015, (b) develop and export the gas in the form of LNG, as is currently being done in Sabah and Sarawak, or (c) export it to Thailand via the pipeline, in the range of 300-600 mmcfd, and keep the remaining 1,150-1,450 mmcfd for future domestic requirements. For Thailand, among these options, the import of gas from Malaysia's Jerneh offshore field via the Gulf of Thailand is a very attractive option because of the field's proximity to its gas infrastructure (100-150 km). However, the implementation has proven difficult because the two countries possess radically different gas utilization plans and different levels of relative needs. While significant progress has been made regarding the exploration in the Joint Development Area (JDA), which is shared between Thailand and Malaysia, there has been no agreement with regard to the import of piped gas. Malaysia is apparently unwilling to accept the Thai-proposed pipeline route, preferring, instead, to pipe the gas to an onshore location on the country's east shore where (a) gas liquids can be extracted for use in Malaysia's chemical and petrochemical industries and (b) the pipeline to the Thai border could also be used to supply gas to the Malaysian cities and industries along the route. There are potential drawbacks in the Malaysian-proposed scheme for Thailand. First, the cost of border-delivered gas is high because Malaysia is insisting on a border price that is similar to the pricing arrangement with Singapore (107% of the Singapore medium fuel oil, spot price), which Thailand feels is unique to Singapore's energy situation and does not take into account the additional transmission lines needed from the border to Bangkok. Second, Thailand would receive dry

gas and thus could not produce the much needed LPG. Third, it would cause the closing of Thailand's planned LPG extraction plant at Khanom.[4/]

3.22 In light of the above difficulties, it was assumed that the gas import from Malaysia would be unlikely, and, at any event, would be delayed until three years after the Myanmar gas has been flowing. On this basis, it is expected that, under a most likely scenario, no gas would be imported from Malaysia. However, under a high gas scenario, it is assumed that the import of Malaysian gas would begin in late 2000 or early 2001, at the rate of 150 mmcfd, and the flow would stay at that level throughout the project life. Further, because all peninsular gas is currently brought onshore at Kertih on the east coast, where the gas liquids are removed and dry gas is piped to the Singapore and Kuala Lumpur areas, and because Malaysia plans to extend the peninsular grid (PGU III) north to Penang near the Thai border, it is also assumed that in the event of gas sales to Thailand, the Malaysian-proposed route eventually would prevail.

3.23 Hence, the Thai-Malaysian future gas agreements will likely involve first, development of the JDA field (which should be encouraged), and second, the sale of gas to Thailand through the Malaysian PGU III grid, once such a grid is in place to Thai border. Thus, Malaysia will not be exporting gas to Thailand prior to completing its domestic pipeline network, namely the construction of the leg extending the PGU III network to the Thai border at Kotabharu. The cost of delivery of 300 mmcfd of gas through the PGU III grid to the Thailand border was based on the development and production cost of the Malaysian gas (US$1.02 per mmbtu) --which does not include any depletion premium for Malaysia-- plus the transportation costs from Kerteh to Kota Baharu on the border (US$0.29 per mmbtu). The transportation costs from Kotabharu to Khanom in Thailand (US$1.06 per mmbtu) was based on 150 mmcfd and thus brought the total cost of Malaysian Gas delivered at Khanom to US$2.37 per mmbtu. This is the basis of the "high" gas scenario. However, the use of Malaysian gas in the Bangkok area is not envisaged because the transportation costs from either Khanom to Bangkok via an onshore route (US$1.47), or from Khanom to Bangkok via an offshore route through the Erawan platform (US$0.93), would be quite high --delivered cost of gas at Bangkok would be US$3.83 or US$3.30 per mmbtu, respectively-- and, therefore, not considered for the purpose of this analysis. Annex 6 provides the analysis for the cost of imported gas from Malaysia.

3.24 In summary, for the period 1993-1998, only the domestic gas supply is considered. From 1998-2005, imported gas from Myanmar becomes available first (late 1997 or early 1998 at the rate of 300 mmcfd), followed, possibly, by gas imported from Malaysia (late 2000 or early 2001 at the rate of 150 mmcfd). As shown in Annex 5, the domestic gas supply is expected to peak between 2000-2005, at a "most likely" level of 1,450 mmcfd and at a "high" level of 2,240 mmcfd. After 2005, it will begin to decline. The forecast of available gas under various scenarios during the three planning periods is given in Table 3.3.

3.25 The parts of Cambodia and Vietnam adjacent to Thai territory in the Gulf of Thailand, and in particular to those areas covered by conflicting claims of sovereignty also have potential for gas discovery. However, due to the time required to resolve those claims and explore and develop the

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4/ This is because the large quantity of gas that would be imported from Malaysia (needed to justify the economics of the project) is greater than demand in Thailand's southern region. Thus, the unused gas would have to be transported to the Bangkok area through the existing Khanom-Erawan pipeline, which means reversing the flow in the pipeline and hence eliminating the need for the LPG plant at Khanom.

fields, the prospects have not been analyzed because they fall outside the time frame of the study. But, given the recent publicity about the possibility of Thailand importing gas from Vietnam's White Tiger field, this source was reviewed; and, it was concluded that such an import under the current situation is not viable. First, the quantity of gas which is presently produced there (80-100 mmcfd) is not sufficient to meet that country's own power generation requirements in the south. Second, current gas production is associated with oil, and hence a function of oil production. Considering the long distance between the White Tiger field and the Thai market, and Vietnam's domestic market requirements, the country's gas production would have to be significantly greater than the present level to warrant a serious evaluation. However, Vietnam's hydrocarbon basins are virtually completely unexplored and major discovery would change the situation.

Coal

3.26 Thailand's attempt to reduce dependency on imported energy prompted the Government to accelerate the development of domestic coal for use in the power sector. A detailed study on development and utilization of coal in Thailand was carried out by the Bank in 1989. The following briefly reviews the latest estimate of the country's coal reserves and their economic costs and value.

3.27 Two government agencies, EGAT and the DMR conduct coal exploration. The DMR grants licenses for exploration and mining and conducts preliminary exploration nationwide while EGAT focuses on more detailed assessments of major basins for its own production for power generation.

3.28 In 1991, about 65% of total coal consumed in the country was for power generation, which uses domestic coal (lignite) exclusively. Non-power use of lignite, mainly in the cement industry, has grown dramatically during the last five years, and is expected to continue growing rapidly until the mid-1990s. In 1991, imported coal represented only 8% of the total coal consumed in the country, all of which was used by the industry. As domestic lignite reserves are limited, the use of imported coal for power generation is also seen as an important supply option.

3.29 Thailand's coal resources are all of relatively low grade, of the quality generally categorized as lignite. Information about lignite reserves is somewhat conflictive since no common standards are used: While EGAT's estimates for minable reserves are based on an underlying economic criteria, DMR's figures refer to physical resources. Estimates for total geological reserves range from 2,050 to 2,300 million tons, while total minable reserves may be around 1,200 million tons, including 1,017 million tons managed by EGAT. EGAT's major minable reserves are located at Mae Moh, which accounts for 812 million tons (around 70% of total minable reserves), 20 million tons at Krabi, 137 million tons at Saba Yoi, 23 million tons at Sin Pun, and 25 million tons at Wiang Haeng.

3.30 An important feature of past coal consumption was the rapid growth of non-power coal demand, which increased at an annual rate of 30% since 1987. This demand is being satisfied by both domestic lignite and imported coal. Table 3.4 presents actual coal demand and supply for the 1987-1991 period, along with projections by DMR and EGAT.

3.31 The projected figures for coal demand and supply for power generation are based on EGAT's current Power Development Plan (para. 3.89). Although the quantity may change in future plans, it clearly indicates that the projected demand for coal, in both the power generation and industry,

cannot be fully satisfied by domestic lignite supply. Power demand forecasts largely exceed domestic lignite-based generation potential, and some of the industrial processes (which require high-quality coal) cannot utilize the low-grade domestic lignite. Consequently, imported coal could account for over 30% of total coal supply by the beginning of the next decade. Current plans consider an intensive use of domestic lignite reserves which, at the projected level of consumption, would be depleted during the 2020s.

TABLE 3.4: THAILAND - Demand and Supply of Coal
(million tons)

	1987	1991	1996	2001
Demand				
Power Generation	5.72	10.45	15.36	25.90
Industry				
- Cement	0.98	2.78	9.80	9.80
- Others	0.36	0.50	0.68	0.92
Total Demand	7.06	13.73	25.84	36.62
Supply				
Power Generation				
- Domestic	5.75	10.45	15.36	17.32
- Imported	-	-	-	8.58
Industry				
- Domestic	1.17	1.90	5.13	7.67
- Imported	0.30	1.38	5.35	3.05
Total Supply	7.22	13.73	25.84	36.62

Sources: DMR, EGAT's Power Development Plan (1992).

3.32 Domestic coal (lignite) is not traded internationally due to its low heat content and high transport costs. Its price in the industrial sector is determined by market forces, and it is traded locally at around 600 Baht per ton (US$23.50 per ton), for a heat value of 4,000 Kcal/Kg. Lignite prices in the power sector, where EGAT plays the role of supplier and consumer, are reflected in a "transfer price" used for planning purposes to analyze expansion investment decisions. This price is set to include production costs (exploration, production and land reclamation), plus a depletion premium aimed at reflecting lignite's opportunity cost. However, it appears that the depletion value currently used by EGAT is underestimated. Further, this price does not include the economic cost associated with the environmental impact of lignite use in power. Table 3.5 presents mission estimates for the depletion premium of Mae Moh's lignite based on the following assumptions: (a) imported low sulfur coal (12,000 Btu per pound) as a replacement fuel; (b) imported coal's CIF price of US$48 per ton (for 1998); (c) domestic lignite's production cost of US$13.26 per ton (1992); (d) discount rate of 10% and (e) a depletion date around 2023.

3.33 Currently, production of domestic coal is subject to a royalty payment of US$0.81 per ton. While this royalty is consistent with the depletion premium computed for the very short-term (i.e., 3 to 4 years), it is much lower than the differential between the effective cost of domestic coal in power generation and the cost of the replacement fuel (imported coal), which would be US$11.3 per ton in 2023. Further, the depletion premium used by EGAT to estimate lignite "transfer prices" is 25% lower

than the mission's estimate. These differences should be corrected, raising the depletion premium to the estimated levels and ensuring that the planning process incorporates a horizon long enough to capture its long-term effects.

TABLE 3.5: THAILAND - Domestic Coal Depletion Premium
(US$ per ton)

Year	Depletion Premium	Total Opportunity Cost
1993	0.65	13.94
1995	0.79	14.15
2000	1.27	14.74
2010	3.28	16.75
2020	8.51	21.98
2023	11.33	24.80

Source: Bank mission.

3.34 The economic value of lignite in power generation, when compared to imported coal, is US$24.80 per ton, i.e., the cost of the replacement fuel (see Table 3.5). This figure is for a longer period, clearly higher than the production cost of lignite and the depletion premium included. However, even at US$24.80 per ton, the economic cost of lignite is less than alternate fuels such as low-sulphur imported coal and low-sulphur fuel oil. But, this relatively low economic cost should not be seen as an indication of the economic viability of lignite for power generation because the environmental cost of lignite-fired power is higher than that of low sulfur coal or oil fired power. If the investment cost required for installing FGD is incorporated, the cost of lignite would increase by about US$8 per ton,[5/] thus reducing the margin enjoyed by lignite and making it less attractive than imported coal after the year 2010.

3.35 The economic benefit of using domestic coal in the cement industry was also assessed, compared with imported coal (for Cha-Am, Thung Song and Saraburi plants) and fuel oil (for Takli). Table 3.6 shows the economic and financial benefits of using lignite in the cement industry, following an avoided cost approach. Computations were based on the following assumptions: (a) no additional capital costs would be required for using coal in existing cement kilns; (b) the imported coal CIF price (for 6,500 Kcal/Kg) would be US$46.75 per ton (for 1996); (c) the fuel oil ex-refinery price (for 10,000 Kcal/Kg) would be US$82.3 per ton; (d) the inland transportation cost would be added to CIF price and (e) the discount rate would be 10%.

3.36 The range of economic benefits (avoided costs) compare favorably with the domestic price of lignite, which varies around US$23 per ton for fuel of similar heat value (see Table 3.6). This suggests that the use of lignite for cement production would be economically viable, as long as the additional environmental costs do not exceed US$7 per ton for Cha-Am and US$13 per ton for the other plants. Financial benefits, which include the impact of fuel taxes, import duties and real interest rates, are even higher. This indicates that the existing tax regime favors the use of domestic lignite, revealing a clear conflict between self-sufficiency and environmental protection objectives.

5/ This assumes that low sulfur coal power generation would not require any emission mitigating measures.

TABLE 3.6: THAILAND - Benefits of Domestic Coal in the Cement Industry
(in US$ per ton of equivalent 4,000 Kcal/Kg lignite [6/])

Plant	Economic Benefits	Financial Benefits
Cha-Am	30.1	45.0
Thung Song and Saraburi	36.8	54.7
Takli	36.1	49.4

Source: Bank mission.

3.37 Imported coal is likely to play an increasingly important role in energy supply for the power sector and industry. In the former, EGAT's current PDP considers additions of 8,100 MW in imported coal-fired plants for the 1997-2006 period, which could account for almost half the expansion during that time. In fact, it could be even larger if current plans for importing natural gas from neighboring countries or LNG from international markets fail to materialize in their timing or scale. It should be noted, however, that imported coal generation is not a short-term solution, since the power plant implementation (which includes in each case new port infrastructure for handling coal) requires careful planning and the solution of the very delicate problem of site selection.

3.38 Although the use of cleaner, imported coal for power is free from many of the environmental problems associated with lignite-fired plants (lignite-production problems such as land surface disturbances and dust concentrations, and many of the consumption-related emissions), compliance with environmental regulations, as well as adequate site selection, is critical so as to avoid any potential delays. Coal supply is not a constraint since it could be imported from several countries in the region, such as Australia, Indonesia and China. Since the early 1990s, imported coal prices have declined mildly, due to weak economic conditions, stronger competition from oil and gas and the re-emergence of South Africa as a major coal exporter. No real price increases are expected in the short and medium term. However, a moderate price rise is expected in the long term, beyond 1995, after a period of reduced investment in coal capacity expansion and as production moves to more difficult locations. For the purpose of this report, coal prices are expected to remain around US$37 per ton FOB until the mid-1990s, reaching US$41 per ton by the end of the decade. Imported coal is subject to a duty of 10%. Annex 2 provides the projection for international coal prices from 1993-2010 which include US$7 per ton for freight and insurance and US$6 per ton for inland transportation.

Liquefied Natural Gas (LNG)

3.39 The high netback value that natural gas produces in the Thai economy warranted an evaluation to establish whether the import of LNG is a viable option. The projected growth in the country's power generation ensures a high-volume gas consumption. This, prima facie, justifies the large scale investments required at the initial stage of LNG import for port facilities and a regasification plant. The potential use of LNG in Thailand would be identical to that of imported gas with regard to its economic value and priority ranking in various applications and sectors: Namely, LNG should be

6/ A relatively high calorific value for lignite (4,000 Kcal/Kg) was used because the calcining kilns of cement plants require a high heating value. However, the precalciner upstream of the kiln, which accounts for almost half the thermal input in the process, can use fuels with low calorific value. Most of the lignite used in cement production is burned in the precalciners or blended with high-calorific value imported coal for use in the kilns.

used primarily in a combined-cycle power plant except for a small quantity used in high netback-value industries. Based on the future requirements of fuels for combined-cycle power plants and the feasibility of constructing LNG plants and securing the supply from international market, it is assumed that 4 million tons per year (mty) of LNG would be required by early 1998, followed by an additional 4 mty by early 2005. In this regard, the LNG option becomes analogous to the gas import option from Myanmar and Malaysia. However, there are two issues associated with the importation of LNG: availability and cost.

3.40 LNG supply is an issue: Only a few LNG plants are coming on-stream and Thailand also has to compete with Japan, Korea and Taiwan in the Asian market. These three countries not only have longer experience and more established credit in purchasing LNG, but their requirements are significantly higher than Thailand's. Therefore, the study examined various potential LNG suppliers with respect to their available reserves of natural gas, existing and planned contracts, the available LNG production capacity and the possibility of expanding their plants. The countries reviewed were Malaysia, Indonesia, Qatar, Brunei, Abu Dhabi, Australia and Oman. While others such as Iran, Yemen, Papua/ New Guinea and Sakhalin were considered, they were deemed unlikely prospects in the near future. Algeria, Nigeria and Venezuela were also considered but were eliminated because their distance would preclude the possibility of competitive prices for long-term contracts. Based on the review, it was concluded that Qatar could be the most viable potential supplier because of its ability to provide large quantities in near future and Malaysia, despite its limited supply capability, offers an attractive option because of its proximity to Thailand and the resulting lower transportation costs. Annex 9 provides a detailed discussion of the issues and options of importing LNG.

3.41 About six sites could potentially receive LNG (three are near Bangkok on the northern coast of the Gulf of Thailand and three are on the west coast of peninsular Thailand). All require substantial port improvements and the three west coast sites require significant pipeline investment from the regasification plant to consuming areas. The principal advantage to the west coast sites is the shorter sailing time from the most likely source of supply (Qatar) and, hence, lower shipping costs. Accordingly, three scenarios have been examined for each level of supply: (a) the Qatar supply source and west coast (Ranong) terminal, which results in shorter marine transport and a longer pipeline to consuming centers; (b) the Qatar supply source and Rayong (S. Bangkok) terminal, which results in longer marine transport and a shorter pipeline to consuming centers and (c) the Malaysian (Bintulu) source and Rayong terminal, which is less likely than Qatar, but has a shorter marine transport and a short pipeline to consumers. Gas supply levels in each case are assumed to be 4 million ton per year (mty) --equal to 485 mmcfd-- and 8 mty.

3.42 The LNG cost consists of five major components: field development and production, liquefaction, marine transportation, regasification and inland transmission. While the costs of field development, production and liquefaction can be reasonably estimated (given the source of supply and the capacity of the liquefaction plant), such an estimate is not meaningful because the prevailing LNG selling prices in international markets are based on either FOB or CIF prices. Marine transportation costs are based on an investment cost of US$270 million for each tanker of 135,000 m^3 capacity, and annual operating costs which, depending on the scenario, range from US$20 to US$124 million. The cost of a regasification plant in Thailand is estimated at US$500-$770 million, depending on the site and the plant capacity. The annual operating costs of the plant are estimated at US$25-$40 million. Inland gas transmission costs vary considerably, depending on the location of receiving terminals, and range from US$95 million for Ao Phai -Bangkok (Rayong terminal) to US$540 million for the Ranong -

Bangkok pipeline. Table 3.7 provides the summary of the unit costs for different scenarios and supply levels.

TABLE 3.7: THAILAND - LNG Cost Components
(US$ per mmbtu)

Scenario I Qatar-West Coast Terminal West Bangkok (Rachaburi)		Scenario II Qatar-Rayong		Scenario III Malaysia-Rayong		
4 mty	8 mty	4 mty	8 mty	4 mty	8 mty	
x	x	x	x	x	x	FOB
0.87	0.88	1.25	1.27	0.38	0.40	Marine
0.50	0.37	0.51	0.38	0.51	0.38	Regasification
0.33	0.26	0.07	0.06	0.07	0.06	Pipeline
1.70	1.51	1.83	1.71	0.96	0.84	Total

Source: Bank mission.

3.43 Malaysian LNG presents a clear advantage, since the transport cost from Malaysia is US$0.87 per mmbtu less than that from Persian Gulf (see Table 3.7). It is more economic to receive LNG purchased from the Persian Gulf at Thailand's west coast rather than at Rayong, because the increase in the marine transportation cost (through the Gulf of Thailand) is far more than the inland gas transmission cost from Ranong to Bangkok. In addition, the total unit cost is sensitive to the size of the project (4 or 8 mty), but this affects only the LNG terminal and, to a lesser extent, inland gas transmission pipelines which represent only 35%-45% of the total costs.

3.44 A preliminary analysis shows that LNG is an option which clearly should be studied more thoroughly because the cost of power generation in Thailand, either through coal, lignite or fuel oil plant, ranges from US¢5.06-6.13 per kwh, depending on the type of environmental control technologies installed. This electricity price corresponds to a gas netback-value of about US$4.5 per mmbtu. As shown in Table 3.7, the highest cost scenario for regasification and transmission in Thailand is about US$0.8 per mmbtu. This gives a netback value of LNG delivered CIF at the terminal, of about US$3.7 per mmbtu, which is slightly higher than the present CIF price of LNG in the Far East (US$3.6 per mmbtu), for countries significantly farther from LNG sources than Thailand.

3.45 With regard to institutional requirements, LNG projects require an integrated system, as there are strong links between upstream and downstream activities. This is reflected in a number of agreements on dedication of gas reserves, production capacity and the designation of ships to specific contracts that have a life of usually more than 20 years. The main actors are LNG suppliers, marine transporters and buyers. As discussed in para. 5.10, entities such as PTT are quite capable of handling the LNG import project and subsequent operations. Negotiating agreements and building up credible financing plans may require several years. Therefore, it is important for Thailand to define an LNG development strategy before starting negotiations with potential suppliers. Annex 9 provides a description of the issues involved in an LNG contract, including the gas supply, the delivery terms, the scope of a gas purchase agreement, the volume of sales, the quality of gas, the price and the methods of payment.

3.46 The price of LNG is the result of negotiations between the buyer and seller. Because the LNG industry is very capital intensive, promoters of the LNG project demand guarantees to insure

financial profitability. This was particularly important in the volatile energy price period, such as the 1970s and 1980s, which led to the renegotiation of LNG prices. In the 1970s, the basic indexing terms were based on the price of oil products in the importing countries. After the second oil shock in 1979, some producing countries claimed strict parity between crude prices and gas prices. In 1980, the indexing of crude prices became the rule in LNG contracts. The collapse of crude prices in November 1986 led to a multiplicity of provisional price agreements that were based on the netback value of crude, since the Government Selling Prices (GSP) no longer reflected market price. At the beginning of 1987, OPEC established new official prices which became the new reference in determining the LNG price. For the purpose of this study, the LNG price is assumed to follow the Japan market, in which the prices are linked to GSP or to spot prices of crude.

3.47 There is some concern regarding the safety of LNG. However, the LNG trade worldwide has reached a high degree of reliability: No major accident has been recorded in all the facilities around the world since the beginning of the industry in 1964. The main risk related to land facilities is the spillage of large quantities of LNG and inflammation of resulting vapor clouds. However, as a result of various large-scale experiments, the LNG behavior is now well known and the constantly updated codes and standards provide a very safe design.

3.48 The study concluded that LNG is an attractive alternative whose implementation, from a safety and institutional point of view, creates no issue: but, it should be investigated further, to better assess the availability of the supplies and costs, particularly those options involving western coast terminals and the possibility of imports from Malaysia. Such additional study is needed because the above costs are only indicative, and the issues of LNG availability and its actual purchasing price can only be determined after a detailed analysis and evaluation, and after an active discussion with potential suppliers. Timing of supply is critical because it could have a considerable impact on the feasibility of the whole project (build-up of consumption).

Compressed Natural Gas (CNG) in Transport

3.49 The use of compressed natural gas (CNG) in transport theoretically offers an attractive alternative to the more expensive and pollutant liquid petroleum fuels. No technical barriers exist to its use because the vehicle conversion technology is easily transferred, the price differential between natural gas and liquid transport fuels in many instances favors CNG and its safety is insured through well-developed engineering codes and standards, major studies and experimentations.[7/] However, CNG still represents a very small share of the transport fuel: Worldwide, only one million vehicles operate on CNG, which is just 0.2 % of the total. This is because the economics of CNG in transport is very market sector specific. It requires a close match between the configuration of the refueling facilities and the pattern of vehicle refueling demand. Also, a substantial number of CNG-powered vehicles are required before the conversion becomes economic and feasible. In addition, a host of other factors would have to come together to ensure a successful substitution program. Natural gas would have to be available at a competitive cost, which often implies that the gas supply infrastructure, such as the pipeline, would have to be justified for other, and much greater, baseload gas demand (such as for power). Further, the public would have to be convinced of its safety and owners of vehicles and

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7/ Countries such as Italy, USA, Canada and New Zealand have used CNG on a commercial basis for several decades. Further, recent experiences in developing countries have been successful and CNG is now available as transport fuel in Colombia, Brazil and elsewhere.

refuelling stations would need incentives to pay for the up-front costs and amortize them through a favorable fuel price differential between CNG and the liquid fuels.

3.50 Based on these conditions, preliminary analyses indicate that in Thailand, where the cost of gas is high, its use can not be easily justified in transport, unless for a specific "captive market," such as for a fleet of diesel buses, and unless the additional environmental benefits can be taken into account. A more detailed analysis of this subject, as well as of the use of LPG in transport, will be provided in a Bank-managed study scheduled to be completed in June 1994. The following paragraphs briefly discuss the economic boundary of CNG use in Thailand's transport sector.

3.51 The determining factor in the viability of a CNG project is the margin between the economic cost of CNG (delivered to the vehicle), and the economic value of the substituted liquid fuel. The environmental benefits of CNG are also important, particularly in Thailand, where the aggregate levels of transport related pollution around Bangkok and other metropolitan areas are acute. The economic cost of CNG at the point of consumption consists of (a) the cost of gas at the CNG outlet of the pipeline; (b) the cost of the refuelling stations (namely the gas compression and dispensing costs); (c) the cost of CNG vehicles (either retrofitted or new CNG-purpose built vehicles); and (d) the costs (credits) associated with reducing the emissions of atmospheric pollutants since CNG combustion emits considerably less hydrocarbons, carbon monoxide and sulphur oxide than liquid transport fuels. The economic value of the liquid fuel substituted by gas is, for the purpose of this analysis, the international CIF price of the liquid fuels which include ocean transport, insurance and losses (see Annex 2), plus inland distribution costs.

3.52 The cost of gas at the CNG outlet of the pipeline, which is assumed to be at Bangkok, would be the economic cost of domestic gas delivered to that city (see para. 6.9). The cost of the refueling stations is a function of its rated capacity, peak delivery demand, and the pipeline gas pressure. Slow-filling stations are equipped with small capacity compressors and the gas feeds directly into the vehicle. Because they require the vehicle to remain in the station for several hours (usually overnight), this type of station is more suitable for a "captive" fleet, such as that used for public transport (diesel buses) or private companies. Therefore, this type of station is more economic because it matches the pattern of vehicle refueling demand. Conversely, the quick-filling stations require larger volume storage systems (cascade), higher compression pressure and peak capacity.[8/] In these, vehicles are easily connected to the cascade and are fueled rapidly. For this reason, they service light passenger cars. Because such a system requires more storage capacity and higher pressure, it is more expensive. The gas unit cost for the two types of stations varies significantly: For a slow-filling station, the cost of compression and dispensing is about US$1.50 per mmbtu, while for a quick-filling station, the unit cost is about US$3.9 per mmbtu.

3.53 The incremental vehicle conversion costs depend on whether the vehicles are built to operate on CNG or need to be retrofitted. In the former, there is generally no significant cost or performance penalty that would change the economics of the option. In the latter, however, the unit cost becomes again the function of the market sector, and therefore varies significantly depending on whether the retrofitting is for passenger cars using gasoline, or for a captive fleet of buses using diesel

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8/ The technology for CNG continues to evolve and new storage systems are becoming commercially available that have the potential to further reduce the cost of gas compression.

oil. The cost of retrofitting light duty passenger cars is estimated at US$4 per mmbtu while for the diesel bus fleet is as low as US$0.90 per mmbtu.

3.54 Accordingly, the total ex-pipeline cost of CNG could vary from about US$7.90 per mmbtu to US$2.40 per mmbtu, depending on the factors discussed above. Given that the economic cost of gas delivered in the Bangkok area (ex-pipeline) is about US$2.00 per mmbtu, the total economic cost of CNG at the point of consumption (in the vehicle) would therefore range from about US$4.40 to US$9.90 per mmbtu. Hence, at the lower end, CNG could compete with the substituted fuels such as gasoline and diesel, which have economic values of about US$6.0 per mmbtu and US$5.50 per mmbtu, respectively. Therefore, it is quite possible that CNG for a particular section of the market (such as the captive fleet of diesel buses around the Bangkok area) could be justified, particularly when the environmental benefits are taken into account. However, given the current cost of the gas produced in Thailand, it is doubtful the country could use CNG on a massive scale. The Bank-sponsored study earlier will address these issues.

Hydropower

3.55 Thailand's hydropower potential is estimated at about 10,600 MW. By the end of 1991, only 3,000 MW (28%) of this capacity had been developed or committed. The remaining potential, based on the current level of information, appears to be less attractive economically and more difficult to develop due to environmental and social pressures. Thus, the potential for domestic hydro generation appears to be limited to a few of the most economic and environmentally benign small-to medium-scale new projects, and low-impact pumped-storage stations for peak generation. In fact, EGAT has no major hydropower project in its agenda and, for the purpose of this study, only a low share (5%-8%) of hydro electricity is expected to contribute to the country's future power demand. However, although the environmental concerns related to developing the hydro projects are real, and their consequences should not be underestimated, no serious attempts have been made so far to clearly define and classify the various environmental problems involved, and, particularly, to quantify the costs of mitigating measures needed to curtail the adverse impacts. Given the country's large and unexploited hydro potential, and given its need for increased energy supply, Thailand should more rigorously re-examine its potential hydro projects; thus, through an enhanced financing plan (schemes such as BOOT or BOT) and through enhanced design of the environmental mitigation plan, some options which are economically and environmentally viable, could indeed become available.

3.56 ***Mekong River.*** A potential source of hydro power for Thailand is the Mekong river and its tributaries. The basin's technical hydropower potential is about 37,000 MW and 150,000-180,000 GWh per year of electricity. A significant part of this is in Laos (51%) and Cambodia (33%). Therefore, from the four riparian countries, the two most populated ones (Thailand and Vietnam) have the highest market for power and yet the lowest share of the basin. However, the development of these sources, particularly the mainstream of the river, is fraught with environmental and resettlement issues that would result from construction of large dams and reservoirs needed to harness the river for power generation. Under the Interim Committee for Coordination of Investigation of the Lower Mekong Basin, a variety of economic, financial and environmental studies have been carried out, for Basin-wide development as well as for the development of mainstream and tributaries. However, the growing influence of NGOs (particularly in Thailand, where they exert a tremendous pressure), has hampered the development efforts. While it is beyond the scope of this study to evaluate the feasibility of Mekong hydroprojects, given the large demand for energy in the region, the consequences of not

developing the mainstream but pursing other alternatives to satisfy the burgeoning power demand of Thailand (and soon Vietnam) through fossil/nuclear fuels, need to be fully evaluated.

3.57 Over the past decades, many studies have defined a range of projects for alternative development of the Mekong river, including a cascade of large multi-purpose projects on the tributaries. One, the Nam Ngum hydroproject in Laos (150 MW), has been implemented. The output of the plant is exported to Thailand (about 600 GWh per year, which is less than 1.5% of the country's total power production). Also, a similar project with manageable environmental consequences, on Nam Theun tributary in Laos, is being contemplated and feasibility studies have been completed. This is discussed below.

3.58 ***Laos hydropower potential.*** Laos hydropower resources are being assessed in a systematic manner by the Mekong Secretariat with the support of the donor community. These resources include several binational projects located near the Laos-Thailand border, as well as many projects within Laos territory. The total potential of these resources could well exceed 15,000 MW; however, most projects are at a very early stage of study. Laos priorities in electrification, formulated in the Second Five-Year Plan (1986-1990) and maintained in the Third Plan, include exporting surplus electricity to Thailand to earn additional foreign exchange.

3.59 Among Laos hydro projects, Nam Theun 2 has the most advanced level of studies and its power generation capabilities and cost estimates are therefore expected to be more reliable than the others. Two more of interest are Nam Theun 1/2, whose feasibility study is underway, and Nam Ngiep, a large project with feasibility studies completed. The latter project is currently seen as less attractive due to its potential environmental impact and large capital investment requirements, both factors associated to the project's scale (2,000 MW). In addition, the development of Nam Ngiep would be in conflict with both the Nam Theun 2 and 1/2 projects, since they compete for common water resources. These two projects are discussed below.

3.60 The feasibility study for the Nam Theun 2 hydroelectric project identifies three main alternative developments schemes: two stages of 300 MW each, a 600 MW single stage and a 600 MW single stage with an underground powerhouse. These alternatives are attractive, particularly in terms of energy generation because, due to the project's reservoir-based regulating capability, their annual plant factor would be quite high, reaching 95% and 85% for the 300 MW and 600 MW alternatives, respectively.

3.61 Although Nam Theun studies do not include a formal power market assessment nor an explicit economic justification, it is clear that, due to its dimension, Nam Theun is essentially an export oriented project which is expected to sell a great part of its energy (more than 90%) to Thailand's power market. It should also be assumed that the project will not face any demand problems since EGAT's northeastern system currently has a peak load of around 900 MW, and has been growing at an average annual rate of over 15%.

3.62 The estimates are that the capital costs would be around US$338 million for the 300 MW first stage, and US$450 million-US$497 for a single stage of a 600 MW plant, with a resulting unit cost range of US$750-US$1,130 per kW. This may be unduly optimistic, and it falls outside the lower end of a wide range of costs based on international and Bank experience in hydro projects. Given that hydropower projects, on average, have higher cost overruns than other power generating technologies (an average of 30% among Bank-sponsored projects), Nam Theun's capital cost estimates

should be used with caution. Nevertheless, even when these costs are increased by 30% and annual plant factors are reduced by 15%, Nam Theun's energy costs of about US¢2.6-2.8 per kWh remain highly competitive compared to Thailand's gas-based, combined-cycle generation (about US¢4.0 per kWh). Table 3.8 shows the project's energy costs, including 5% transmission losses and assumptions for capital costs and plant factors [9/].

TABLE 3.8: THAILAND - Nam Theun 2 Hydropower Plant Generation Costs
(US¢ per kWh)

Plant Factor %	Alt. I 300 MW 1st stage	Alt. II 300 MW 2nd stage	Alt. III 600 MW	Alt. IV 600 MW and Underground P.H.
95	2.1	n.a.	n.a.	n.a.
85	2.3	n.a.	1.8	1.6
75	2.5	1.1	2.0	1.8
65	3.0	1.3	2.3	2.1
Capital cost increased by 30% and plant factor reduced by 15%				
80	3.2	-	-	-
70	-	-	2.8	2.6
60	-	1.8	-	-

Source: Project's feasibility study and mission estimates.

3.63 These figures suggest that the best solution would be the development of a single 600 MW stage with an underground powerhouse. However, before a final decision is made about adopting any alternative, it is essential to undertake additional geotechnical investigations and hydrological studies, and devise a set of measures to minimize the project's environmental impact. These measures include establishing a protected area and policies for compensation and resettlement, and conducting studies on forestry, wildlife, fisheries, and public health. These measures --and their costs-- have sparked internal political problems that are causing delay. The problems have raised a cloud of uncertainty about the project's future, and it is now difficult to make any firm plans about its implementation; however, if the issues were resolved, the project could be commissioned by the beginning of the next decade.

3.64 The Nam Theun 1/2 hydropower project, which will accelerate the electrification program in Laos' central provinces, is a medium size (210 MW), low environmental impact project which is the initial development of the vast hydropower resources in the Nam Theun basin. Due to the low power demand in Laos, Nam Theun 1/2 would also be selling most of its energy (1,300-1,600 GWh per year) to Thailand. It should be noted, however, that the feasibility study has yet to be completed. Therefore, the estimates about the projects' technical characteristics and costs should be considered preliminary. Nevertheless, these indicate that the capital costs of Nam Theun 1/2 would be around US$265 million, including transmission line investments in Thai territory. However, the cost of US$1,260 per kW may be optimistic if compared with international experience. Further, the energy production of Nam Theun 1/2 would be affected by the development of Nam Theun 2, since the latter

9/ Generation costs in Table 3.8 include transmission investments in Thai territory to connect with EGAT's main grid. If these investments are excluded to reflect "border energy prices," the above generation costs would be reduced by 10%-12%.

project would divert water from the basin and reduce its energy production by 19%, (although not its capacity). In spite of these adverse factors, Nam Theun 1/2 when compared to other power supply options remains as an attractive project for Thailand. Table 3.9 presents its energy costs, assumptions about the impact of Nam Theun 2, and higher capital costs [10/].

TABLE 3.9: THAILAND - Nam Theun 1/2 Project Generation Costs
(US¢ per kWh)

Capital Costs	Without Nam Theun 2	With Nam Theun 2
Consultant's estimate	2.4	2.9
Bank estimate (30% higher)	3.1	3.8

Source: Bank mission and project feasibly study.

3.65 Although Nam Theun 1/2 costs are higher than Nam Theun 2's by almost US¢1.0 per kWh, and, as mentioned, its cost estimates are less reliable, the smaller project offers a set of advantages: (a) its environmental impact is relatively minor as it is a run-of-river project with many underground structures; (b) it has a shorter lead time, could be commissioned by 1999 and (c) it has reduced capital requirements which may facilitate its financing. Nevertheless, activities in both Nam Theun projects should continue; although, once a decision is made about which project should begin first, it is likely that, due to Laos's limited credit, only one project could be built at a time.

3.66 ***Myanmar Hydropower Potential.*** Myanmar hydropower resources are also considerable, particularly in the Salween River basin adjacent to Thailand's border. However, these resources remain almost unexplored. The lack of data on the technical characteristics of this hydro potential, i.e., on the identification of sites, hydrological and geological conditions, and the social and environmental impact of its development, constitute a serious constraint for assessing its attractiveness for Thailand's power market. Further, considering the long lead-time of hydro projects (10-12 years), plus the political uncertainty associated with a establishing power trade agreement between both countries, it is thought that the import of hydroelectricity from Myanmar is not a viable solution for Thailand during this study's timeframe.

Nuclear Energy

3.67 The Government is considering a nuclear power program as an option, mainly to diversify fuels and increase the reliability of the power supply. Currently, it is evaluating the nuclear experience of other countries, the nuclear technology available, and the countries that supply it. Moreover, the Government recognizes it needs an appropriate nuclear regulatory framework and institutional capacity. Therefore, it is contemplating reorganizing the existing nuclear-related entities and the framework so these could be in place by the time the two proposed nuclear plants become operational in about 2006. EGAT's Power Development Program (PDP), which results from a least-cost expansion approach, anticipates commissioning the first nuclear unit (1,000 MWe) in January 2006, followed by the second 1,000 MWe unit in July 2006.

10/ Generation costs in table 3.9 include transmission investments in Thai territory. If these costs are excluded to reflect "border energy prices", energy costs would be reduced by approximately 17%.

3.68 Currently, nuclear power accounts for approximately 17% of the total electricity generated in the world and is produced in over 30 countries. Worldwide, there are about 430 nuclear reactors either in operation or under construction, which have a total capacity of 400,000 MWe. The share of nuclear power in these countries varies widely, ranging from France, in which it accounted for about 75% of its electricity in 1992, to Brazil and Pakistan which generated less than 1% in the same year. Nuclear-based power production is not a new technology, but consideration of the nuclear option as an alternative source of energy is a complex and somewhat subjective decision. This is because the decision on whether or not a country should go nuclear goes beyond mere economics and covers a host of other issues (some of which are difficult to quantify) such as the perception of risks and the regulatory measures needed to protect the public from the environmental consequences that may result from breakdowns or the disposing of radioactive waste. The evaluation becomes even more complex in the case of developing countries where operations may be less stringent and it is more difficult to enforce strict rules and regulations. These complex problems on the one hand, along with the recent (and projected) low-price trends of the fossil fuels and the perceived benefits associated with nuclear power on the other hand, create conflicting signals for policy makers who must evaluate the nuclear option. A detailed evaluation of these issues is beyond the scope of the study, particularly as it concludes that a nuclear option program is not economic for Thailand (para. 3.73). Therefore, the analysis focuses on a broad assessment of the economic viability of nuclear-based power production in Thailand, rather than evaluating an optimum nuclear program or technology. Specifically, the study attempts to answer two questions: (a) Is a nuclear program, as an alternative source of fuel for power generation, economically viable for Thailand? (b) Can the country's institutions meet the challenges posed by the nuclear option? A brief discussion of the last issue is essential because the country may decide to introduce nuclear power to diversify fuels and meet other strategic objectives, regardless of the economics involved.

3.69 *Cost.* The arguments in favor of nuclear power played a crucial role during the 1960s and 1970s, when the concerns over human health, public safety and environmental impacts were always weighed against the purported substantial economic benefits. Namely, proponents argued that while the capital costs of the nuclear plants would be much higher than for fossil fuel plants, fuel costs would be significantly lower. However, recently, even questions about economic viability have become legitimate: Not only do the safety and environmental concerns have become more pronounced, but their costs can now be better quantified. Also, the price of fossil fuels did not reach the high level projected. Although a few countries claim that their nuclear power costs are less than those associated with fossil fuels, such comparisons have to be weighed carefully with respect to consistencies in the cost parameters. Namely, in most of these cases, the nuclear and coal power plants were constructed at different times, with different construction periods, financing costs, exchange rates and price increases. Nonetheless, some countries can indeed produce power more cheaply with nuclear plants. For example, the French report that the cost of nuclear power in 1992 was US¢4.15 per kWh, compared with US¢6.04 for coal-fired and US¢8.11 for oil-fired power. Also, the Canadians report a consistent-based cost of Canadian ¢4.06 per kWh for the nuclear and Canadian ¢4.22 per kWh for the coal-fired power plant. However, it should be born in mind that the French achievement is the result of over 30 years of centrally-controlled experience, the standardization of nuclear technology, and the development of a complete and consistent set of codes and regulations as well as of cohesive nuclear organizations responsible for designing, manufacturing and constructing the entire nuclear technology. In the vast majority of other countries, this experience does not exist and the transfer of nuclear technology will not be an automatic panacea. In these, the economics of the nuclear option is questionable.

3.70 The central issue is estimating future capital and operating costs, which have proven to be quite problematic. The broad category of components include: (a) initial capital costs, which include all direct and indirect expenditures during a relatively long period; (b) decommissioning capital costs, at the end of the useful life of the plants; (c) operating and maintenance costs, which consist of fixed and variable costs including managing all radioactive waste (except the spent fuel) and (d) fuel costs, which include uranium, the costs associated with conversion, separation and fabrication works, and those for managing the waste disposal of the used nuclear fuel. Estimates for these components based on past costs are generally not meaningful, because key parameters, such as the size of the reactors, the complexity of the design and the required regulatory measures, have changed significantly in recent years. First, with regard to the size, to meet economy of scale criteria, the average size reactor (which was 600 MWe in the 1960s) is now about 1,200 -1,400 MWe. In addition, the number of units built in a series substantially affects the cost of the nuclear program:[11/] For Thailand, EGAT plans to install two 1000 MWe units. Second, design changes have a major impact. About 85% of the reactors currently operating are water-based reactors. Of these, pressurized water reactors (PWR) represent 55%, boiling water reactors (BWR), 20%, and pressurized heavy water reactors (PHWR), 10%.[12/] The designs, however, are continually improved to enhance safety and reliability features. Third, a new consideration is the cost associated with the management of radioactive waste; and, estimating them is complicated, because it is difficult to predict the waste repository behavior hundreds of years into the future. While the waste with a low or medium-radioactive level may be properly stored and the costs of such storage can be estimated with a reasonable degree of accuracy, the same does not apply to the potentially much more harmful waste, such as used fuel. Thus, the "back-end" cost of the nuclear fuel could vary widely, depending on environmental and policy considerations, from US¢0.1 per kWh for onsite storage to US¢0.4 per kWh for final disposal.

3.71 For these reasons, the average construction time for most nuclear plants has increased substantially. While the French averaged about 70-80 months for the first units of the 900 MWe series, but reduced the time of subsequent units to about 60 months, in the US, it took an average of about seven years to construct a nuclear power plant in 1976, but now takes about 13 years (for the same plant). Within such long-lead times, many cost parameters change, as well as governmental administrations and political objectives; and, these elements contribute to unreliable cost estimates. For Thailand, even assuming an efficient implementation program, for a grass-root project, a realistic construction period is assumed to be not less than eight years, and more likely 10 years.

3.72 EGAT estimates the investment cost of a nuclear plant to be at US$1,430 per kW, while those of a steam coal-fired plant were estimated at US$1,350 per kW, only 5.6% less than the nuclear plant. As mentioned above, the range of capital costs for nuclear plants varies significantly, from those in the US that were four times the capital costs of coal-fired power plants and six times that of gas-fired power plants,[13/] to the French cost experience, which is very favorable. However, it is highly

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11/ Various studies show an economy of scale exponent of 0.4-0.6 for nuclear power plants in the capacity range of 600-1,400 MWe. With regard to number of units, the study has also shown that if the cost of a 10-unit program is one, the cost of one unit is 1.6-2.2.

12/ The pressurized heavy water reactor (PHWR) design is also known as CANDU, the Canadian deuterium uranium reactor.

13/ The average capital cost of a nuclear plant in the US has increased from US$1,250 per kW in 1976 to US$3,700 per kW in 1986 (in 1990 dollars).

unlikely that the capital cost of a nuclear plant for Thailand could be as low as that estimated by EGAT. In fact, the Bank mission estimates that the capital cost of the first 1000 MWe unit in Thailand would be about US$2,500 per kW and the second unit, about US$2,000,[14] with the unit cost of power about US¢9 per kWh for the first unit and US¢7.5 for the second. As shown in Table 3.14, these unit costs are significantly higher than those of power generated from other fuels. The nuclear power cost for Thailand is based on a capacity factor of 70%. Although countries such as Canada and Korea experienced capacity factors of up to 86%, others have registered figures that were considerably lower: For example, India's capacity factor has been as low as 41%. Even assuming that Thailand could achieve a higher one, say, in the range of 75%-85%, the analysis shows this still does not affect the economics of the option so as to change its ranking in comparison with other fuels. Other assumptions used in calculating the power costs, such as the plant life, the O&M costs, the cost of interest during construction, the fuel cost, and the discount factor, are given in Table A12.1 of Annex 12.

3.73 In conclusion, based on the Bank's higher estimates, nuclear power is not a competitive option in Thailand when compared to gas, lignite, coal or fuel oil-fired generation, even after the investment and operating costs of the pollution-mitigating technology such as flue gas desulphurization (FGDs) units on lignite and coal-fired power plants are considered. However, regardless of its economic viability, Thailand may still choose the nuclear option to diversify the fuel supply and reduce energy imports, as well as promote technology transfer, domestic participation in nuclear projects and financial policy objectives.

3.74 ***Institutional and Regulatory Issues***. Given that this study concludes the nuclear option is not economically viable, major institutional issues that have a major impact on the nuclear investment decision, will not be addressed in detail. Thus, this section discusses the adequacy of the existing institutions to handle nuclear power, only briefly.

3.75 At present, there is no active plan to implement a nuclear program in Thailand. The main entities involved in nuclear activities are the Office of Atomic Energy for Peace (OAEP), which is under the Ministry of Science, Technology and Environment (MOSTE), and EGAT, the state electricity company. OAEP assumes responsibilities in three main areas which include: (a) a regulatory role, pursuant to the Atomic Energy for Peace Act, with respect to public safety and environmental protection as well as compliance with international requirements; (b) a coordinating role, for nuclear affairs and foreign relations, acting as the secretariat of the Thai Atomic Energy Commission and (c) a research and development (R&D) role, conducting R&D in nuclear technology and safety, which involves the operation of the national research reactor. OAEP has 10 divisions plus the Nuclear Facility Regulatory Center. The divisions are engaged in traditional nuclear research activities such as radiation measurements, radiation protection, radioactive waste management, isotope production and distribution. The Nuclear Facility Regulatory Center is responsible for assessing safety features associated with any proposed nuclear facilities (see Annex 10 for organizational charts).

14/ These totals do not include some important costs associated with specific nuclear technology, such as decommissioning costs, which are assumed to be around 10% of the initial capital cost. Nor do they include the long-term costs associated with the disposal of radioactive waste. Although from a strict economic point of view, heavy discounting tends to reduce substantially the importance of these costs, they are major issues which need to be addressed at the start. In particular, high-level radioactive waste, such as used fuel, is a controversial issue which requires a sound waste-management program involving infrastructure, adequate regulation, and special arrangements with fuel suppliers and regional organizations. Thailand is considering returning the waste to the country supplying the system, but it is doubtful whether potential suppliers would agree to this.

3.76 EGAT is the other main entity involved in nuclear activities, housing a division that deals with the operational aspects of nuclear power technology. It has identified five potential nuclear plant sites and activities such as planning and quality assurance, safety and technology assessments are part of its ongoing nuclear work.

3.77 The Government is reorganizing the nuclear sub-sector to adapt to the needs of a nuclear power program (see Annex 10 for a chart showing the proposed organization). This includes:

(a) Modifying the Atomic Energy for Peace Act in order to prepare a legal basis for ensuring that nuclear plants are sited, designed, constructed, commissioned, operated and decommissioned without undue radiation risks to plant personnel and the public, and with proper regard to the environment;

(b) Establishing principles, regulations and criteria for (nuclear-related) health and safety and environmental protection;

(c) Establishing regulations and procedures for emergency preparedness on and off the site of the nuclear power plant; and,

(d) Establishing safety standards based on IAEA Safety Standards (NUSS) and Code and Practice and Safety Guides in all activities concerning government organizations, siting, design, operations and quality assurance.

3.78 The existing nuclear-related institutions are weak and, for the most part, orientated towards the academic and research fields. They are not capable of providing the necessary support for an effective regulatory framework, a training and education program, or engineering capacity. A good institutional framework, which includes an appropriate organizational arrangement, program management plans, regulatory requirements, financing plans, a public outreach program and a national participation plan, is fundamental to the success of a nuclear program.

3.79 The necessary organizational framework requires substantially more than the present number of staff, level of expertise and mix of skills. Because of the special safety and environmental features of the nuclear option, 10 to 15 years may be required to establish the independent, national capability needed to effectively manage such a program. Any effort to develop it, should be program- rather than project-oriented. Qualified manpower will be also required in the regulatory agency (see Annex 10), in industry and in scientific and educational institutions. However, the greatest demand will be in the executing agency.[15/] Annex 10 provides a schematic presentation of the steps to be taken in order to complete a nuclear plant by 2006.

15/ During the early implementation phases, 50-100 highly qualified professionals would be needed. These numbers could increase sharply as the implementation progresses. Construction activities have by far the largest manpower requirements, in the order of 5,000 people, of which about 85% are technicians and craftsmen. Professionals during the design and construction phase are needed primarily for project management and engineering (250-350). A staff of about 170-270 highly trained staff would be needed for operations and maintenance. Finally, about 1,000 staff would be required at the time of fuel reload and scheduled maintenance, an activity which should be considered during the planning phase, since these services may have to be contracted outside the country.

3.80 The objective of the regulatory framework would be to safeguard the public and the environment; and, because safety and environmental mitigation technology costs can be high, the implementing agency should not attempt to reduce the nuclear program's costs at the expense of the regulatory functions. If Thailand pursues the nuclear power option, it must establish an appropriate regulatory and institutional framework by 1995, and complete it by 1997. It is particularly important that the regulatory body be independent, have the trust of the general public, be staffed with competent people and have transparent operating procedures. To accomplish these ends, OAEP's regulatory functions should be separated from its R&D functions.

3.81 Public acceptance of nuclear technology, more than any others, is an essential ingredient of a successful program. Lacking this can delay the construction, which raises costs substantially, not only due to "stopped-work," but also to requirements for additional safety features.

3.82 National participation during implementation of the project can be achieved in several ways. One option is a high domestic participation in program implementation; however, for its first nuclear power plant, Thailand would most likely import the technology, know-how and a substantial portion of equipment, goods and services. But if the program involves a sequence of nuclear units on a reasonable scale and time frame, the increasing use of national capability and infrastructure would then be feasible. In this case, the country would actively participate through its utility company, regulatory body, national industry and other relevant organizations. Under this option, the project implementation would be carried out through an engineering-management consulting firm. The other option is to select the technology and supplier on the basis of an a priori decision, which is equivalent to a turnkey contract, whereby a single contractor assumes overall responsibility for the work.

3.83 The first option (high domestic participation) involves wide involvement in the project and program implementation, which has a positive impact on the country's development. At the same time, it offers the possibility of more competitive bidding which should lead to lower costs. However, it implies higher responsibility and project risks, as well as higher probability of cost overruns. The second option (the turnkey type) usually involves lower risks and utilization of standard techniques, but generally implies higher costs, limited direct control over the project, and reduced technology transfer. The preparatory and implementation activities of the executing agency (EGAT) would be substantially different for the different options.

Demand Side Management and Electricity Conservation

3.84 Thailand's power sub-sector is gradually moving towards an integrated resource planning (IRP) approach for power generation. In so doing, the Government has recognized that saving energy or capacity through demand-side management (DSM) programs or other electricity conservation measures, is equal to adding capacity and, hence, another way to meet future demand. Two programs currently underway involve a master plan for DSM and time-of-day tariffs aimed at reducing peak demand.

3.85 The DSM master plan proposes an initial five-year pilot program through which EGAT would invest in saving approximately 1,427 GWh per year by the end of the fifth year. These savings, which also include a capacity saving of 225 MW, would be achieved through incentives to produce and/or install energy-efficient technologies among all categories of consumers. The program cost is estimated at US$ 188 million. Potential benefits are calculated to be about US$ 260 million in capital

investment and US$30 million per year in fuel expenses. This would equal a very low energy supply cost of US¢2.05 per kWh, assuming, conservatively, that the energy efficiency gains would have a ten-year impact.

3.86 Current DSM plans have a modest scope since their benefits would account for only 4% of total expansion needs during 1992-1996. However, economic indicators strongly suggest that DSM is a viable and highly attractive solution that should be considered as a realistic option for meeting power demand in the long term. To succeed, the DSM program must develop an appropriate institutional and human infrastructure to sustain the effort in the longer term; also, the power utilities must have clear incentives to pursue such a program. If successful, DSM could reduce peak demand by 2,000 to 3,000 MW over the next decade, which is a reduction of about 10%.

3.87 The structure of electricity tariffs is being gradually improved through the introduction of time-of-day tariffs for major consumers. This measure aims to increase the power system's load factor, thus reducing expansion needs. Nevertheless, the success of the program has been hampered by the lack of an adequate tariff structure to distribution companies, which do not pay demand charges to EGAT (para. 2.41).

B. Power Sector Expansion Plan

3.88 EGAT operates 114 generating units supplying electricity to four regions. In 1991, total generating capacity was 9,610 MW; 2,429 MW were from hydro, 4,907 MW from conventional steam-electric turbines (oil/gas and lignite-fired plants), 2037 MW from combined-cycle and 238 MW from open-cycle gas turbines. Regions are presently interconnected through a transmission grid of 18,200 Km which includes a variety of voltages up to 500 kV. In addition, private generators have an overall installed capacity around 1,064 MW, used exclusively for self-generation and backup purposes.

3.89 EGAT's latest Power Development Plan (PDP) was formulated in September 1992 and was based on the Load Forecast Working Groups (LFWG) power demand projections of 1991. This plan has two distinct periods. The first period, from the present to the end of 1996, includes a set of ongoing projects consisting of various technologies and fuel options, adding up to 5,895 MW of new capacity to the system. It involves a large amount of gas-fueled plants (4,489 MW), including some dual fuel oil/gas plants, lignite-fired plants (750 MW), conventional hydropower and pumped-storage stations. Most of these projects have already been approved and their environmental studies have been completed. The second period, from 1996 to 2006, considers an expansion of around 17,000 MW which, in addition to the ongoing power generation options, would introduce imported coal-fired plants (8,100 MW beginning in 1998) and nuclear plants (2,000 MW in the year 2006). These two technologies are proposed because natural gas and lignite supplies are expected to reach a plateau by the end of the decade. Table 3.10 shows the main features of EGAT's PDP, including a breakdown by types of generating plants and time periods. A list of all projects recommended in the PDP is presented in Annex 11.

3.90 The present study focuses on the second period (1996-2006), since it is for these years that most power expansion investment decisions have yet to be made.

TABLE 3.10: THAILAND - EGAT's Power Generation Plan - 1992-2006
(Capacity Additions in MW)

Type of Plant	1992-1996	1997-2001	2001-2006	Total
Steam Plants				
Natural Gas/Oil	1,200	0	0	1,200
Lignite	750	450	2,100	3,300
Coal (Imported)	0	4,100	4,000	8,100
Combined Cycle	2,689	2,300	300	5,289
Gas Turbines	600	0	0	600
Nuclear	0	0	2,000	2,000
Hydro	656	686	800	2,142
Total	5,895	7,536	9,200	22,631

Source: EGAT's PDP.

3.91 In general, EGAT's long term planning is sound. It is based on a systematic approach and a realistic data base for project costs and technical operating characteristics. Some improvement may be possible, however, in the following areas:

(a) EGAT's capital costs ratio between combined-cycle plants and open-cycle gas turbines (1.16) appears to be low and not in line with international experience (1.45 or above). Consequently, the capital costs of gas turbines are overestimated, which introduces a bias against gas turbine peak load generation. In fact, the PDP only includes one gas turbine project (Wang Noi), justified as an emergency solution.

(b) As discussed in para. 3.70, estimating nuclear power capital costs is, these days, a difficult task since no new plants have been built under normal conditions in more than a decade. Nevertheless, EGAT's estimates of US$1,590 per kW for the first and US$1,272 per kW for the second unit (average of US$1,430 per KWh), seem unusually low when compared to a range of US$1,700 - US$3,000 per kW, which represents worldwide experience outside the US.[16/]

(c) The unserved energy cost of US¢8 per kWh used by EGAT is based on the energy generation cost of a backup gas turbine unit. However, this approach fails to capture the real economic costs of an unexpected power outage which, most certainly, would be much higher. The optimization of a power system reliability level should be based on short-run outage costs, i.e., the costs incurred by electricity users as an immediate consequence of a particular supply problem affecting them. These costs are a function of many variables such as the outage duration, time of day, income levels, level and type of industrialization and thus, produce a remarkably large range of outage cost estimates. However, all these estimates, which vary from US¢50 per kWh to as high as US$2-US$3 per kWh, are higher than EGAT's estimates. The use of low outage costs in power planning would tend to reduce reserve capacity, and thus reach unduly low reliability levels.

16/ Capital costs for new nuclear plants in the US have been assessed at US$4,000 per kW.

(d) As mentioned in para. 2.20, the current planning practice is too conservative in the treatment of demand side measures.

(e) It is unclear whether the computer model used as an optimization tool for generation expansion (the WIGPLAN computer package) is the most appropriate for Thailand. It seems that the objective function is unable to capture the long-term impact of power investment decisions because the model is constrained to the expansion period (1993-2006). A more comprehensive model that would incorporate a longer time frame, as well as DSM and environmental impacts, with better technical and training support, should be considered.

3.92 In order to assess the impact of modifying various assumptions along the lines discussed above, EGAT carried out, upon the Bank mission's request, additional optimization analyses using the same demand forecast and planning tools. Three scenarios of natural gas supply were analyzed (see Table 3.11): Scenario I is based on supply of domestic gas plus about 300 mmcfd from Myanmar; Scenario II is based on a high domestic gas production plus gas imports from Myanmar and Malaysia (150 mmcfd after 2001); and Scenario III is based on Scenario I, plus import of LNG (para. 6.19).[17/] Optimized generation sequences for Scenarios I, II and III are presented in Annex 11. Additional assumptions common to all three scenarios are:

(a) The capital cost of gas turbines is based on US$500 per kW (instead of PDP's cost of US$564 per kW);

(b) A low cost of US$2,000 and US$1,600 per kW, for the first and second nuclear plants, respectively[18/];

(c) Fuel costs were based on: no real increase for crude oil, an increase in the cost of lignite as a function of the depletion premium (see Table 3.2) and imported coal costs based on the CIF price of US$41 per ton (for 1998); and

(d) The economic cost of non-served energy is US$1.00 per kWh (instead of PDP's estimate of US¢8 per kWh).

17/ Scenarios I, II and III in the power sector correspond to Scenarios C (low gas), A (high gas) and B (LNG), respectively, in the fuel supply option (para. 6.19).

18/ As discussed in para. 3.72, the Bank mission's estimates for the capital costs of nuclear plants used in the study are US$2,500 and US$2,000 per kW, which are the basis for power costs in Table 3.14. However, in order to test the sensitivity of the analysis and demonstrate that even under relatively low capital cost prices, the nuclear option continues to be uneconomical, these low capital costs (US$2,000 and US$1,600 per kW) were used in the power expansion optimization runs.

TABLE 3.11: THAILAND - Gas Supply Available to EGAT
(in mmcfd)

Year	PDP (Medium)	Scenario I (low gas/coal)	Scenario II (high gas)	Scenario III (LNG)
1993	792	760	760	760
1998	NA	1,150	1,350	1,150
2005	1,710	1,231	2,402	2,201
2010	NA	517	1,721	1,487

Source: Bank mission.

3.93 The comparison of EGAT's PDP with the expansion plans resulting from above three fuel supply options, shows the impact of capital cost adjustments (higher for nuclear and lower for gas turbines), a higher cost of power outages, adjusted fuel prices and an increased gas supply. The main findings after undertaking these corrective measures are:

(a) The nuclear power plant (2x1000 MW) is no longer in the least-cost expansion plan even when using a relatively low capital cost in the range of US$1,600-US$2,000. Consequently, total capital requirements for generation expansion are reduced for the planning period, as nuclear generation is replaced by less capital intensive technologies (imported coal thermal), and overall fuel costs increase.

(b) A greater availability of natural gas for power generation provides significant benefits because coal-fired plants would be deferred, consumption of fuel oil and diesel would be reduced, as would the requirements of imported coal. Nevertheless, an important coal-fired program would still be required after the year 2001, as gas supply would reach a plateau. Table 3.12 compares the capacity additions, by technologies, for each scenario.

(c) The expansion plan does not appear to be sensitive to the use of higher power-outage costs. However, it is sensitive to lower capital investment costs for gas turbines because its results in installation of 200-400 MW additional capacity.

TABLE 3.12: THAILAND - Comparison of Capacity Additions for 1997-2001
(in MW)

Type of Plant	PDP	Scenario I (low gas/coal)	Scenario II (high gas)	Scenario III (LNG)
Lignite	450	650	350	450
Imported Coal	4100	2000	0	0
Combined Cycle	2300	4200	7200	6600
Gas Turbines	0	400	200	200
Hydro	686	686	660	660

Source: Bank mission.

3.94 The impact of a reduced gas supply on the power sector can be noticed when the expansion plans for Scenarios I and II are compared (Scenario III is similar to Scenario II). It is, as

expected, quite large, thus confirming the economic value of gas for power generation. The main findings in the reduced gas supply scenario are:

(a) The total cost for generation, including capital investment, O&M and fuel costs, would increase by about 7% over the planning horizon (1993-2006);

(b) In the absence of additional gas, the combined cycle program would be reduced by 3,000 MW over the 1997-2001 period. This capacity would need to be replaced by high capital cost coal-fired plants (2,000 MW), diesel-fueled gas turbines (200 MW) and the early implementation of one lignite plant (300 MW) over the same period;

(c) The shortage of gas supply would have to be covered, in the short run, by an increased consumption of heavy fuel oil based on existing capacity, and later by imported coal and lignite. By 1998, heavy fuel oil consumption would be almost doubled. Over the 1997-2006 period, total additional fuel consumption would include: (a) heavy fuel oil, 132 million barrels; (b) imported coal, 52.3 million tons and (c) lignite, 25.9 million tons.

(d) In the event that LNG is made available instead of additional imported gas, the expansion program would be similar to that of Scenario II. However, fuel costs would be much higher.

3.95 Table 3.13 shows power energy generation by type of fuel.

TABLE 3.13: THAILAND - Energy Generation by Type of Fuel
(in %)

Fuel	PDP		Scenario I		Scenario II		Scenario III	
	1998	2005	1998	2005	1998	2005	1998	2005
Local/Imported Hydro	6.6	4.6	6.6	4.6	6.6	4.6	6.6	4.6
Natural Gas	44.3	26.7	55.2	38.2	59.0	66.7	55.2	68.2
Heavy Fuel	26.3	11.7	16.4	9.4	12.6	7.1	16.4	5.6
Diesel	1.6	0.4	0.8	0.6	0.8	0.6	0.8	0.6
Lignite	21.2	21.6	21.0	21.0	21.0	21.0	21.0	21.0
Imported Coal a/	0.0	35.0	0.0	26.2	0.0	0.0	0.0	0.0

Source: EGAT and Bank mission.

a/ No imported coal is consumed during 1998 because new steam electric plants will initially operate on fuel oil. Coal imports are expected to begin in 2000.

C. Comparison of Power Generation Costs

3.96 A project-by-project comparison of generation costs was undertaken in order to establish power investment priorities for different load operating levels (plant factors) and periods of time, as well as to explore the sensitivity of these priorities to variations on key parameters, such as fuel and

capital costs. As gas-fueled power generation is the least-cost solution for Thailand, the gas netback values were estimated vis-a-vis lignite, oil and coal-fired alternatives in order to assess the economic viability of importing gas from neighboring countries. The analysis was done for power plants included in the PDP, which are typical of each generating technology. Although the generation cost estimates presented in this section were obtained without the recourse to a comprehensive systems approach, real supply and demand constraints were captured in the use of variable plant factors and constrained energy production during a short initial period which does not exceed three years. Assumptions on technical and economic parameters, in great part based on EGAT's data base, are presented in Annex 12.

3.97 Power generation options were compared for the 1998-2005 and 2005-2010 periods, taking into account the availability and expected costs of alternative energy sources for each period. In addition to the parameters listed in Annex 12, sensitivity analyses were conducted for various assumptions including gas turbines and nuclear plant capital costs, addition of FGD to coal-fired plants, fuel costs and plant factors.

3.98 Table 3.14 compares power generation costs for several base load plants as the plant factor varies from 70% to 60%. These figures reveal that for the initial period (1998-2005), gas-fueled combined-cycle is the least cost generation alternative among thermal generation and/or domestic supply options. Gas combined-cycle is followed by lignite-fired thermal generation (without FGD) and the two conventional hydros, Mae Lama Luang and Mae Taeng. Also, the gas combined-cycle cost advantage increases as the plant factor decreases, since it is a relatively low capital-intensive technology. When FGD is added to lignite plants, its cost would approach the levels of imported coal generation.

3.99 Among import alternatives, Laos hydro appears to be the most attractive power generation option, even cheaper than the use of domestic gas in power. It should be noted, however, that due to the complexities of hydropower projects, which have required long lead times and costly investigations, the potential contribution of Laos' hydropower resources to Thailand's power system is limited (the capacity of both projects adds to 810 MW only) over this period. Other import options, such as imported coal and LNG-based combined cycle, would be competitive to the extent that domestic gas supply would not be sufficient for meeting the system's power demand.

3.100 The very low costs estimated for the energy saved through the DSM pilot project are an indication that, if successfully implemented, DSM measures should be a first priority course of action.

3.101 For the period beyond the year 2005, when domestic gas and lignite would no longer play an important role, the most important supply options would be based on imported fuels. Among them, the most attractive appear to be coal-fired thermal and LNG combined cycle, two options which offer large scale alternative programs.

Table 3.14: THAILAND - Base Load Generation Costs
(US¢/kWh)

Plant	70% Plant Factor	60% Plant Factor
1998-2005		
Combined Cycle (gas)	4.0	4.3
(LNG)	5.4	5.7
Lampang (lignite), no FGD	4.1	4.6
with high efficiency FGD	5.1	5.7
Ao Phai (coal)	5.0	5.5
New Thermal (coal), no FGD	5.2	5.7
New Thermal coal with low eff. FGD	5.6	6.2
Mae Lama Luang (hydro) a/	-	4.6
Mae Taeng (hydro) b/	-	4.6
Nam Theun 2 (hydro, Laos) c/	2.6	-
Nam Theun 1/2 (hydro, Laos) d/	3.8	-
Demand Side Management (DSM) e/	2.1	-
2005-2010		
Combined Cycle (LNG)	5.5	5.8
New Thermal (imported coal), no FGD	5.2	5.7
New Thermal (imported coal), with low eff. FGD	5.7	6.3
New Thermal (fuel oil), with low eff. FGD	5.7	6.2
Nuclear f/; First unit	9.0	10.3
Second unit	7.5	8.6

Source: Mission estimates.
a/ Medium load plant; annual plant factor: 39%
b/ Medium load; plant factor: 49%
c/ For investment costs 30% higher than consultant's estimate.
d/ For energy supply reduced by Nam Theun 2's diversion, and investment costs 30% higher than consultant's estimate.
e/ Average cost of KWh saved through DSM pilot project.
f/ Capital costs based on average non-US. experience, i.e., US$2,500 and US$2,000 /kW for first and second unit, respectively.

3.102 Sensitivity analyses on the above mentioned variables gave the following results:

(a) The netback value of natural gas in combined cycle generation vis-a-vis lignite fired plants with high efficiency FGD, i.e., the second best fuel option during the 1996-2005 period, is US$3.88 per mcf for a plant factor of 70%. Compared to imported low-sulfur coal generation (with low efficiency FGD), natural gas netback value increases to US$4.41 per mcf. If power plants are to be operated at a lower plant factor, say 60%, these values would increase. Table 3.15 shows a set of netback values of gas in power generation.

(b) If natural gas costs remain constant at the base case level (US$2.47 per mcf projected for 1998), lignite and imported coal costs would have to fall dramatically to highly unlikely levels (US$4 per ton and US$27 per ton respectively) in order to make lignite and coal-fired generation competitive.

(c) Coal-fired generation costs increase by about 18% when high efficiency flue-gas desulfurization (FGD) is added.

(d) In the long term, LNG costs (including CIF prices plus all inland costs associated with the gas supply at the plant) would have to be in the order of US$4.00 per mcf, so as to be competitive with imported coal generation.[19/]

(e) Nuclear power generation does not appear competitive unless the capital investment drops to US$1,250 per kW, a highly unlikely assumption (para. 3.72).

TABLE 3.15: THAILAND - Netback Values of Gas in Power
(US$ per mcf)

Alternative Generation a/	Plant Factors	
	60%	70%
Lignite with High Efficiency FGD	4.24	3.88
L.S. Imported Coal with Low Efficiency FGD	4.72	4.41
L.S. Fuel Oil without FGD	4.85	4.75

Source: Bank mission.
a/ Netback values are provided only for base cases.

3.103 In general, EGAT's expansion plan is consistent with the Bank estimates for generation costs. In fact, the plan takes into account gas-fueled combined-cycle and lignite-fired plants, which are the lowest-cost solutions, subject to supply constraints. As these two energy sources decline, additional demand would be supplied by imported coal plants, which appear to be, by that time, the least cost solution. The only major difference refers to the nuclear power plant, which is explained by the higher capital costs considered by the Bank and discussed in para. 3.72.

3.104 Table 3.16 compares power generation costs for peak-load power plants at plant factors between 35% and 25%. Generally speaking, gas-fueled combined cycle and gas turbines (open cycle) appear to be the most attractive peak generating options, provided that no additional cost is required for enabling these plants to operate in a peak fashion. Cost figures reveal that, due to its higher efficiency, combined cycle generation would remain highly competitive even at very low utilization levels. On the other hand, diesel-fueled plants would provide a more costly peak energy (40% to 50% higher) but a more versatile operation.

19/ Estimated figures compare LNG-fueled combined cycle generation to low sulfur coal-fired generation without FGD.

TABLE 3.16: THAILAND - Peak Load Generation Costs
(US¢ per kWh)

Plant	35% P.F.	25% P.F.
- Period 1998-2005:		
Combined Cycle (gas)	5.9	7.5
Gas Turbines (gas)	6.2	7.5
(LNG):	8.4	9.8
(diesel):	9.3	10.8
Lam Takhong (pumped storage) a/		10.8
Nam Khek (pumped storage) b/		9.1
- Period 2006-2010:		
Gas Turbine (gas)	6.5	8.0
(LNG):	8.6	10.0
(diesel):	9.4	10.8

Source: Mission estimates.
a/ Plant factor: 11%
b/ Plant factor: 17%

3.105 The costs of pumped storage hydro plants are site specific and not directly comparable to thermal peak generation options since these plants, while operating at a fixed plant factor, are limited to supplying capacity and not energy. Nevertheless, peak energy costs were estimated for Lam Takhong and Nam Khek. These figures are competitive with those of LNG- and diesel-fueled power plants.

D. Primary Energy Supply Requirements

3.106 To project primary energy requirements over the planning period, various transformation coefficients were applied to the final energy consumption forecasted above (para. 2.32). For oil, final consumption was increased by 4% to allow for refinery fuel use and losses. (This was the actual coefficient registered by the country's three refineries in 1991). For domestic gas, final consumption was increased by 11%, reflecting the gas system's own use as well as the reduction due to the extraction of gas liquids. No adjustments were applied to imported gas and LNG. For electricity, to estimate power generation requirements, the final demand was increased by 13.5% to allow for distribution and transmission losses, as well as station uses and the pumping of energy. Non-energy uses of fuel, such as naphtha for petrochemicals, were also considered. Table 3.17 shows the total primary energy requirements for 1993-2010 by type of fuel including the aggregate quantity of electricity required. The different fuels required to generate this aggregate quantity of electricity were then calculated and added to the non-power primary energy requirements to obtain total primary energy needs.

TABLE 3.17: THAILAND - Non-Power Primary Energy Supply Requirements
(ktoe)

Fuel	1993	1998 A	1998 B&C	2005 A	2005 B&C	2010 A	2010 B&C
Oil	20,937	29,142	29,142	45,670	45,670	59,458	59,458
Gas	657	2,757	2,757	2,944	2,944	3,091	3,091
Imported Coal	380	533	828	800	1,280	1,020	1,690
Lignite	1,450	2,130	2,130	3,470	3,420	4,580	4,580
Non-Commercial	7,471	8,058	8,384	8,588	9,308	8,808	9,852
Total Non-power	30,895	42,620	43,241	61,472	62,622	76,957	78,691
Power (Elec)	5,183	7,985	7,280	13,057	11,695	18,012	16,067
TOTAL	36,078	50,605	50,521	74,529	74,317	94,970	94,738

Source: Bank mission.
A - Gas dominating; B - LNG dominating; C - imported coal dominating

3.107 Table 3.18 provides the total primary energy requirements including the fuels required for the power sector.

TABLE 3.18: THAILAND - Projected Primary Energy Requirement
(ktoe)

		1998			2005			2010		
	1993	A	B	C	A	B	C	A	B	C
Oil	23,694	32,028	32,537	32,537	48,354	47,594	48,796	63,278	61,587	63,717
Gas	7,376	14,691	12,923	12,923	24,178	22,402	13,826	18,305	16,237	7,661
Coal	380	533	828	828	800	1,280	8,895	15,066	15,844	22,733
Lignite	4,536	6,238	5,875	5,875	10,070	9,331	9,331	13,516	12,551	12,551
Hydro	378	527	480	480	601	538	538	720	643	643
Total Commercial	36,364	54,017	52,644	52,644	84,003	81,145	81,387	110,885	106,862	107,305
Non-Commercial	7,470	8,058	8,384	8,384	8,588	9,308	9,308	8,808	9,852	9,852
TOTAL	43,834	62,075	61,028	61,028	92,591	90,453	90,695	119,693	116,714	117,157

Source: Bank mission.
A - Gas dominating; B - LNG dominating; C - imported coal dominating

CHAPTER IV

ENVIRONMENT

A. Introduction

4.1 The purpose of this section is to address the environmental consequences of future energy supply options for Thailand. The focus is on pollution associated with energy use in the electric power and industrial sectors, where energy consumption is predicted to grow rapidly over the next twenty years. Transport, which will also pose significant environmental impacts, is the subject of other recent World Bank studies, so will not be dealt with in detail here. The main environmental effects will be related both to the quantity of energy consumed and to the mix of the different types of fuels used. The main purpose of this report is to examine the relationship between alternative energy supply options and environmental impacts. However, the actual level of pollution in the future in Thailand will also depend on the adoption of pollution control technologies, government regulatory and fiscal policies, and market incentives for reducing pollution emissions.

4.2 In this report, the energy supply forecasts for Thailand's power sector were generated by EGAT's power system planning model. Alternative assumptions on installed capacity, costs and energy supplies available (i.e., natural gas) were provided to EGAT by the World Bank. Non-power energy supply forecasts were generated by the World Bank. Based on energy consumption forecasts for the power sector, and Bank estimates of non-power energy demand growth, the quantity of various pollutants have been estimated. The analysis here estimates the level of pollutants resulting from the alternative energy supply options assuming: a) no change from current practices with regard to fuel quality and pollution-control technologies, b) alternative pollution-control measures, including improved fuel quality and additional pollution-control equipment. The magnitude of the costs involved in controlling pollutants is also examined.

4.3 While there are a number of important environmental impacts associated with energy production and consumption, the assessment here is confined to atmospheric emissions from energy consumption. Environmental impacts from energy production (coal mining or oil and gas drilling) and consumption-related pollution of water and land, will not be addressed in detail in this study.[1/] Also not addressed in this section are the environmental implications of hydroelectricity, nuclear power, or liquified natural gas (LNG). While the air pollution emissions associated with these energy sources is nil, they pose other serious environmental and social problems. Since there are few new hydroelectric projects included in the power expansion plans of EGAT, and thus the additional environmental costs will be low, the environmental impacts associated with hydroelectric projects are not addressed in this study. For LNG and nuclear, which are covered in detail in Chapter III of this report, the environmental costs are assumed to be incorporated within the design, construction, operation and regulatory costs of a state-of-the-art LNG or nuclear facility.

1/ Economically efficient ex-mine prices of energy commodities should include externalities, such as costs of land reclamation, disposal of solid wastes, reduction of air emissions (to meet national standards) and other environmental damages that occur during the production process.

4.4 The environmental impact of future energy supply options for Thailand will focus on three air pollutants: sulphur dioxide (SO_2), the oxides of nitrogen (NOx), and particulates, or total suspended particulates (TSP).[2/] The most compelling reason for limiting the analysis to these three air pollutants is that they are responsible for the largest portion of environmental and health damage associated with energy consumption. A second consideration is that emissions of TSP, SO_2 and NOx are relatively easy to estimate since they are a function of the amount of energy consumed, type and quality of fuel, and combustion technology; other pollutants, such as liquid and solid wastes, are more difficult to estimate since they are not always directly correlated with energy consumption.

B. Background and Methodology

4.5 A model has been constructed for this study which estimates the emissions of SO_2, NOx and TSP based on future energy demand forecasts. The following sections describe the major impacts and sources of these pollutants, the methodology that has been used to estimate future emissions, and simulations of past emissions (1982-1991) which were used to "calibrate" the model.

Properties, Sources and Impacts of Key Pollutants

4.6 ***Particulates***. Particulates refer to solid and liquid matter that remains suspended in the air for varying lengths of time depending on the size and density of the particles. Particulates may include a variety of chemicals including metal and hydrocarbon traces. The size of particulates affects their residence time in the air and also the impact on human health. Particles larger than 500 microns are rapidly removed from the atmosphere by gravity, while small particles -- from about 0.1 to 500 microns (10^{-6} meter) -- are the most dangerous to human health. In the U.S., and increasingly in other countries, there are no standards for TSP, but only for the smaller particles, such as PM-10 (particulate matter, smaller than 10 microns).

4.7 The consumption of fossil fuels, industrial processes (cement), and construction projects account for the majority of man-made particulate emissions. Particulate emissions from fuel consumption are a function of the ash content of the fuel, the temperature of combustion, the design of the boiler, stove or engine, and the degree of particulate removal from exhaust streams.

4.8 Of concern from a health standpoint are the fine and ultrafine particles (smaller than 10 microns and smaller than 2 microns respectively) which are most easily retained and absorbed into the lining of the lungs. Ultrafines contain most of the toxic or carcinogenic elements associated with coal combustion, such as H+ ions, trace metals (nickel, beryllium, arsenic, mercury, cadmium) and organic compounds. In addition to size, the factors which influence the interaction between particulates and the human body are chemical composition, other physical characteristics (shape, density), atmospheric concentration, duration of exposure, and individual susceptibility. A recent study of environmental

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2/ Two other hazardous air pollutants -- lead and carbon monoxide -- result from energy use, primarily from the transport sector. Because the transport sector is being examined in detail in other World Bank studies, these pollutants will not be dealt with in this study.

health risks in Bangkok estimates that high levels of particulates are responsible for between 9 million and 51 million "restricted activity days" and between 300 and 1400 excess mortality cases each year.[3/]

4.9 ***Sulphur Dioxide (SO_2).*** The major anthropogenic source of SO_2 is from the combustion of coal and oil. In the case of coal, 90-95 percent of the sulphur content of the coal is oxidized into sulphur dioxide during combustion. Natural sources, such as volcanos, account for some two-thirds of global atmospheric sulphur (H_2S, SO_2, SO_3); however, man-made sources tend to be much more concentrated, prevalent in urban and residential areas, posing a greater health hazard to humans.

4.10 Sulphur dioxide oxidizes in the atmosphere to form sulfates, which can have adverse effects on human health, animals and plants, and property. Sulphur dioxide is considered one of the most dangerous gases to man. Sulphur (and NO_X) emissions act synergistically with ultrafine TSP, forming acid aerosols (sulfuric and nitric acid) which can have serious local effects. Respiratory illnesses have been shown to be directly associated with acid aerosol concentrations in the air. Sulphur and nitrogen emissions are also the primary contributors to acid rain, which can have both local and regional effects.

4.11 ***Nitrogen Oxides (NOx).*** Nitrogen oxides are produced from nitrogen and oxygen in the air during combustion, with the quantity of NOx produced being directly proportional to the temperature at which combustion takes place. While SO_2 and TSP emissions depends to a large extent on fuel characteristics (sulphur and ash content), the production of NOx is related to the combustion process itself. Motor vehicles and stationary combustion sources, such as power plants, contribute to the production of NOx in the atmosphere.

4.12 Exposure to nitrogen oxides is believed to increase the risks of acute respiratory disease and susceptibility to chronic respiratory infection. Nitrogen dioxide (NO_2) contributes to heart, lung, liver, and kidney damage, and can be fatal at high concentrations. As noted above, NOx is also an acid rain precursor.

Estimating Emissions from Energy Use

4.13 The study estimates emissions of SO_2, NOx, and TSP for Thailand to the year 2010. The two key variables used to estimate emissions are energy consumption and emission coefficients, the latter being the amount of pollution per unit of energy.

4.14 ***Energy Consumption Data.*** Historical energy data (1982-1991), covering natural gas, fuel oil, diesel fuel, gasoline, lignite, imported coal, and biomass fuels (fuel wood, charcoal, paddy husk, bagasse), has been taken from Thailand government publications.[4/] In cases where the data was

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3/ USAID, Office of Housing and Urban Programs, "Ranking Environmental Health Risks in Bangkok, Thailand," December 1990, p. 21. Using the dose-response functions estimated by this study, a separate analysis estimates that the costs of particulate pollution in Bangkok are between US$330-450 million annually. Shin, Euisoon, et al "Economic Valuation of Urban Environmental Problems -- With Emphasis on Asia," January 28, 1992, p. 104-113; report prepared by the Environment and Policy Institute, East-West Center, for the Urban Development Division, The World Bank.

4/ Department of Energy Affairs (DEA), Ministry of Science, Technology and Environment, Thailand Energy Situation, 1991; Oil and Thailand, 1991.

given in mass or volume units, it has been converted to energy equivalent units according to the conversion factors for Thailand.

4.15 Future energy consumption has relied on the forecasts and scenarios prepared by the Bank. As can be seen from Table 4.1, the power sector accounted for the majority of Thailand's natural gas and lignite consumption in 1991 and a substantial fraction of fuel oil consumption as well. The energy demand forecast used to calculate the quantity of air pollutants emitted from combustions of various fuels in the power sector are based on EGAT's recommended Power Development Plan (PDP) for 1992-2006, and on two additional scenarios prepared by the Bank. For the PDP scenario, the Bank has extrapolated the power demand forecasts of EGAT from the period 2007-2010. The two additional energy demand scenarios for the power sector are Scenario I (Low Gas Scenario), and Scenario II (High Gas Scenario).[5/] Additional details on these scenarios are provided in Chapter VI. Energy demand forecasts for the non-power sectors have been made by the World Bank.

TABLE 4.1: THAILAND - Power Sector Fuel Use, 1991
(percentage)

Fuel	% Used by the Power Sector
Natural gas	93.7
Fuel oil	51.7
Diesel	0.7
Lignite	80.6
Coal (imported)	0

Source: Data from DEA, 1991.

4.16 ***Emission Coefficients***. The total amount of SO_2, NOx and TSP emitted into the atmosphere has been estimated by applying emission coefficients to past and future energy consumption in Thailand. Emission coefficients reflect the amount of each pollutant, by weight, emitted per unit of fuel (in standard energy units, such as tons of oil equivalent). The basic emissions coefficients for this study were taken from a 1990 report by the Thailand Development Research Institute (TDRI).[6/] Emission coefficients for each pollutant reflect differences in fuel type (e.g., gas, oil, coal) and combustion conditions, such as whether the fuel was consumed in a utility boiler or in a transport vehicle. For most air pollutants, the greatest variation in coefficients is a function of fuel, as shown in Table 4.2.

5/ For the purpose of the analysis of this Chapter, the LNG Scenario (B) was not considered separately since a high gas scenario is analogous to the LNG scenario.

6/ TDRI, Industrializing Thailand and its Impact on the Environment, Research Report No. 7, "Energy and Environment: Choosing the Right Mix," December 1990. The coefficients for the TDRI study were estimated for Thailand by Resource Management Associates (Wisconsin, USA), based on emission factors from USEPA, WHO, USDOE, OECD and TDRI.

TABLE 4.2: THAILAND - Emission Coefficients for TSP, SO_2 and NOx (Industry)
(gram/Megajoule and index, natural gas = 1)

	TSP		SO_2		NOX	
Fuel Type a/	g/MJ	Index	g/MJ	Index	g/MJ	Index
Natural Gas	0.001	1	0.00005	1	0.078	1
Fuel Oil	0.076	52	1.433	30,456	0.166	2
Diesel	0.014	9	0.467	9,919	0.104*	0.9
Lignite (Mae Moh)	5.731	3,897	2.541	53,988	0.955	12
Lignite (Li)	3.257	2,215	1.444	30,687	0.955	12
Imported Coal	2.124	1,444	0.360	7,655	0.379	5
Fuel Wood	0.250	170	0.031	664	0.075	1

Source: Bank mission estimates.

a/ Fuel characteristic assumptions are as follows:
Natural gas - 244 kcal/scf; Fuel oil - 9500 kcal/liter, 3% sulphur; Diesel fuel - 8700 kcal/liter; Lignite (Mae Moh) - 2500 kcal/kg, 27% ash, 2.9% sulphur; Lignite (Li) - 4400 kcal/kg, 19% ash, 1.4% sulphur; Imported coal - 6300 kcal/kg, 0.5% sulphur; and Fuel Wood - 3820 kcal/kg.

4.17 Without flue-gas controls, domestic lignite in Thailand produces 2,000 to 3,000 times as much TSP per unit of equivalent energy as natural gas. Differences in the quality of the same fuel can also affect emissions. For example, the average quality of domestic lignite used by industry (Li) is much better than that used by the power sector (Mae Moh).[7] Mae Moh lignite has a higher sulphur and ash content resulting in more SO_2 and TSP per unit of fuel consumption. In addition, because Mae Moh lignite has a lower energy value, more has to be consumed for the same useful energy.

4.18 In addition to fuel characteristics, emissions are dependent on the manner in which fuel is consumed. For example, the amount of NOx produced from transport vehicles is much higher than from stationary sources due to the high temperature at which fuel combustion takes place in internal combustion engines. According to Resource Management Associates, the emission factors for Thailand used in the 1990 TDRI report were assigned according to the type and vintage of the capital equipment. For this study, separate emission factors have been applied to available sectoral energy consumption data for Thailand to reflect fuel consumption by internal combustion engines (e.g., transportation, agriculture), small boilers (industry), and large boilers and generators (electric power).

4.19 Emission control technologies will also affect the amount of pollutants released to the atmosphere. The following discussion outlines the technologies currently used in Thailand to control

7/ The reason for this is partly due to economics; it is not viable to ship lower-quality lignite long distances from the large northern coal mines to users near Bangkok. Industries near Bangkok use higher-quality Li lignite, while most of the lower-quality Mae Moh lignite is used by mine-mouth power plants.

TSP, SO_2, and NO_X, and the assumptions that have been employed for estimating baseline emissions for this study (see also para. 4.60).

4.20 TSP. All of the power plants at Mae Moh have electrostatic precipitators (EP), which have removal efficiencies between 90-99%. Using an average of 96% particulate removal for the power sector resulted in TSP emissions estimates that were very close to those estimated by TDRI for 1988. Although not estimated here, mining and transport of lignite produces roughly an additional 10% in TSP emissions, which are for the most part uncontrolled. Most industries in Thailand use one or a series of cyclones which results in up to 50% removal of particulates. Past and future TSP emission estimates for industry have assumed the same level of control as currently.

4.21 SO_2. There are presently no dedicated SO_2 control technologies in use in Thailand in industry or the power sector. Two new units at Mae Moh (Units 12 & 13) are reportedly being equipped with flue gas desulfurization (FGD) systems, and various Thai government officials report that all new power plants using domestic lignite or imported coal will have FGD systems. Baseline estimates of SO_2 emissions have been made assuming no future SO_2 controls, while alternative scenarios have been made assuming various levels of technical control on lignite- and coal-fired power plants (paras. 4.35-4.38).

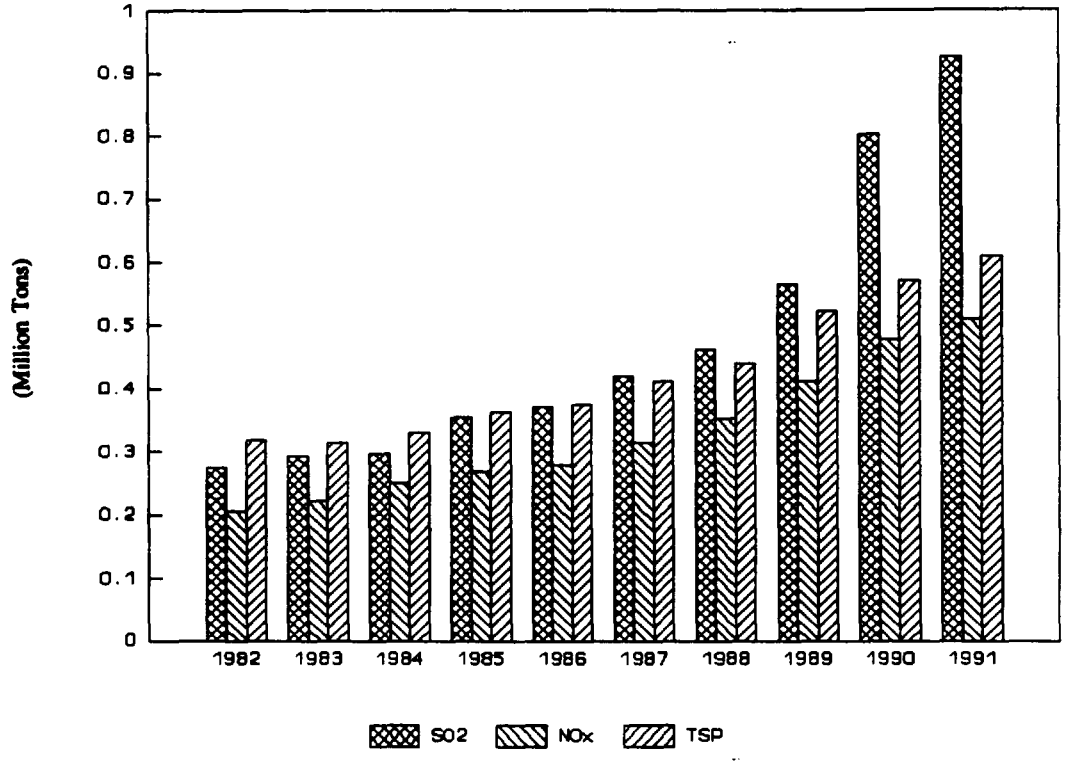
4.22 NOx. According to EGAT, NOx emissions at Mae Moh are being controlled through the use of overfire and 2-stage combustion techniques and through the use of low-NOx burners. There is apparently no NOx control used by industries in Thailand. Again, the emissions estimates for NOx have not been adjusted to account for additional NOx controls in the future.

C. Current and Past Emissions

4.23 Rapid economic and energy consumption growth in Thailand during the 1980s produced a worsening in air quality. Using past energy data from DEA and emission coefficients from TDRI, emissions of SO_2, NOx and TSP have been simulated for Thailand for the period 1982-1991. Estimates of emissions for all three pollutants during the 1980s and early 1990s are presented in Figure 1. A summary of emissions by fuel and by sector for 1991 are given in Tables 4.3 and 4.4.

4.24 *SO_2*. The power and industrial sectors accounted for around 90% of SO_2 emissions during the 1980s. Overall, SO_2 emissions increased more than three times during the decade, surpassing 900,000 tons by 1991. As can be seen in Figure 1, the most dramatic increase in sulphur emissions occurred from 1989-1991, corresponding to the increased consumption of lignite at the Mae Moh power plants. In 1991, SO_2 emissions from Mae Moh amounted to 440,000 tons, or roughly half of Thailand's total emissions (see Table 4.5).

Figure 1: Thailand - Simulated Emissions, 1982-1991



Source: Based on data from DEA and TRDI; Bank mission estimates.

4.25 The structure of SO_2 emissions changed throughout the 1980s in Thailand, primarily due to changes in fuel use. Fuel oil, which accounted for over 60% of SO_2 emissions in 1982, contributed less than 40% of emissions in 1991. The share of emissions from lignite increased from 26% to 56% between the same period, with the absolute level of emissions increasing five-fold to more than 500,000 tons. Had domestic natural gas resources not increased from less than 10% to more than 20% of total commercial fuel use, SO_2 emissions nationwide would have been significantly higher during the 1980s.

4.26 *NOx*. Transport was the leading source of NOx emissions throughout the 1980s, accounting for about half of Thailand's total emissions. According to the model, the consumption of diesel fuel contributed over half of the country's NOx emissions, with the transport share dominating both in terms of total fuel use (only small amounts of diesel are used by industry and power) and in terms of emissions per unit of energy (28.2 g/kg for transport; 3.8 g/kg for industrial). Although lignite accounted for only 15% of NOx emissions by 1991, NOx emissions from lignite increased 3-fold in percentage terms and more than 7-fold in absolute tons of emissions between 1982-1991.

TABLE 4.3: THAILAND - Emissions by Fuel, 1991
(tons)

	SO_2	%	NOx	%
Natural gas	11	0%	27,749	5%
Fuel oil	348,937	38%	44,832	9%
Diesel	41,715	5%	268,984	53%
Gasoline	7,600	1%	54,957	11%
Lignite	514,620	56%	75,070	15%
Coal (imported)	3,988	0%	4,197	1%
Biomass fuels	8,942	1%	34,755	7%
TOTAL	925,813	100%	510,545	100%

Source: Bank Estimates.

TABLE 4.4: THAILAND - Emissions by Sector, 1991
(tons)

	SO_2	%	NOx	%	TSP	%
Utility	621,130	67%	99,013	19%	35,712	6%
Industry	222,570	24%	60,125	12%	311,019	51%
Transport	64,807	7%	260,676	51%	115,526	19%
Agriculture	7,882	1%	58,469	12%	14,017	2%
Other	9,425	1%	32,262	6%	134,259	22%
TOTAL	925,813	100%	510,545	100%	610,533	100%

Source: Bank Estimates.

TABLE 4.5: THAILAND - Mae Moh's Contribution to Thailand's SO_2 Emissions, 1982-1991
(tons)

Year	Lignite/Mae Moh /a		Total
1982	63,263	23%	274,910
1983	58,988	20%	292,617
1984	72,938	25%	296,879
1985	172,388	49%	355,434
1986	175,688	47%	371,613
1987	214,763	51%	420,258
1988	221,100	48%	461,905
1989	254,250	45%	566,341
1990	370,313	46%	803,001
1991	439,688	47%	925,813

Source: Bank Estimates.
/a Mae Moh accounts for the majority of lignite-fired capacity in Thailand.

4.27 *TSP*. Industry is the single largest contributor of particulate emissions in Thailand. While industrial energy consumption accounted for about one-third of TSP emissions in 1982, by 1991 the percentage had increased to over one-half. In 1991, lignite accounted for 54% of TSP emissions from the industrial sector. It is interesting to note the large but declining importance of biomass fuels to particulate emissions. In 1991, bagasse still accounted for roughly one-third of TSP emissions from industry. Widescale burning of brush and undergrowth for non-energy purposes is probably not included in national estimates of renewable energy use, but would appear to be responsible for a great deal of particulate emissions in rural areas. Particulate emissions from transport, which amounted to 19% of total TSP emissions nationwide in 1991, is of considerable concern since the emissions are concentrated in urban areas and are emitted largely at ground level.

D. Future Emissions

4.28 Using the same methodology as for historic emissions, estimates of future emissions of SO_2, NOx and TSP have been made. Two sets of factors which affect the level of emissions have been analyzed: the energy supply mix, and pollution-control measures. In the first instance, changes in emissions result from alternative energy supply scenarios, such as the percentages of coal, oil, and gas in Thailand's overall energy supply balance. To isolate the changes in emissions resulting from energy supply changes, other factors, such as the existence of pollution-control technologies, are held constant. In the second case, various pollution-control strategies are examined in terms of their effect on overall

emissions and relative costs. Among the pollution-control measures examined are improved fuel quality for imported coal and fuel oil and the installation of FGD equipment on new and existing lignite plants and on new imported coal plants.

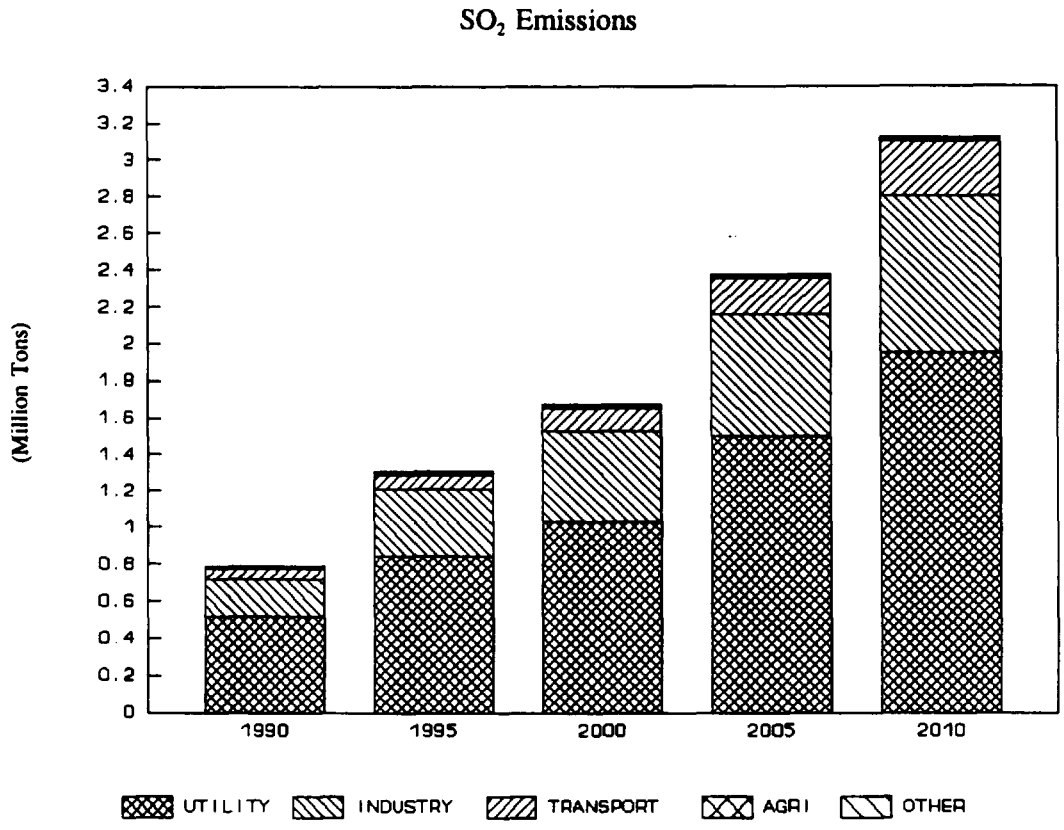
No Change in Current Pollution-Control Practices

4.29 As discussed in para. 4.15, emissions of SO_2, NOx and TSP have been estimated based on several energy supply scenarios. Given the limited quantities of natural gas and domestic lignite available to Thailand over the next two decades, the energy balance is assumed to be increasingly met by fuel oil and imported coal and possibly by LNG (nuclear power was not selected - see para. 3.73). Baseline emissions estimates have been made assuming no changes in current environmental standards, technical controls or fuel specifications, so that the effect of fuel supply changes alone can be discerned. Among the current environmental practices which were incorporated into the baseline emissions model are: (a) no FGD for controlling SO_2 emissions on power or industrial plants; (b) high-efficiency (average 96%) EP for all power plants; (c) low- to medium-efficiency cyclones for controlling TSP in industry; and (d) high-sulphur (3%) fuel oil used by all sectors, most importantly power and industry. In the next section, some of these assumptions are relaxed, to see their effect on emissions.

4.30 One of the key factors affecting future emissions, particularly of SO_2 and TSP, is the planned expanded use of lignite and coal for power generation. There are currently 11 lignite-powered units at Mae Moh, with a total installed capacity of 2025 MW and two smaller units at Krabi in the south, with a combined capacity of 34 MW. Under the reference scenario (PDP), EGAT plans to expand lignite-fired capacity by 900 MW by the turn of the century and coal-fired capacity by 3100 MW. Five years later, an additional 2400 MW of lignite-fired capacity and 5000 MW of coal-fired capacity is planned to be added by EGAT. By 2005, over 13,000 MW of lignite- and coal-fired capacity is planned to be installed in Thailand, up from just over 2,000 MW in 1993 (see Table 3.10 and Annex 11).

4.31 Under all energy scenarios, the consumption of lignite by the power sector grows from around 12 million tons in 1992 to 17 million tons by the year 2000. Beyond 2000, lignite consumption expands rapidly reaching 24 million tons per year under Scenario I and 28 million tons under Scenario II by 2005. Imported coal consumption increases under all scenarios after 2000, most rapidly under the low gas scenario.

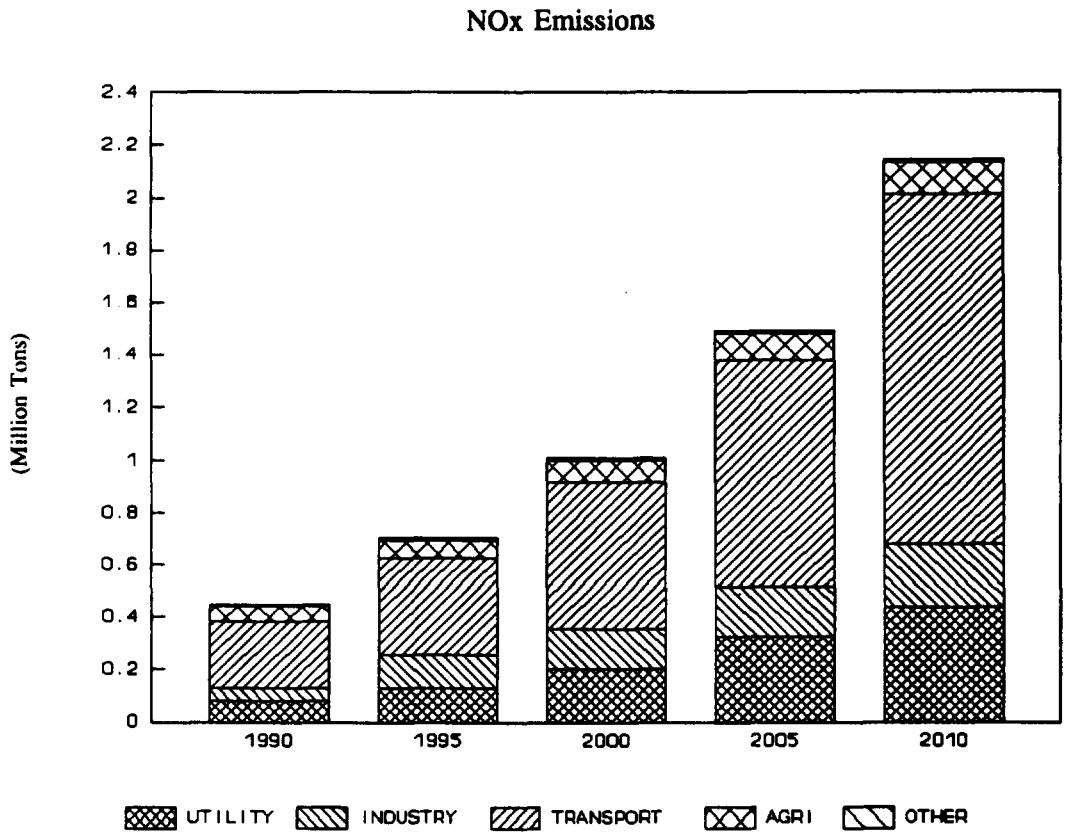
Figure 2: Thailand - PDP Scenario, Current Practices, No-Change Option



Source: Bank mission estimates.

4.32 *SO_2*. Without changes in current control measures (i.e., no FGD or coal-cleaning), SO_2 emissions rise from around 800,000 tons in 1990 to over 3 million tons by the year 2010 under all scenarios. Although SO_2 emissions are lowered somewhat in the High Gas scenario, the increased use of domestic lignite and imported coal after 2000 results in the overall steady increase in SO_2 emissions. Assuming no additional controls, lignite consumption contributes around 45% of SO_2 emissions in the year 2010 while fuel oil and imported coal account for 37% and 10% respectively. On a sectoral basis, the power sector accounts for 61-65% of SO_2 emissions in the year 2010, followed in importance by the industrial sector which accounts for 24-27% of emissions. (See Appendix 13 for detailed emissions by sector and by fuel for each scenario.)

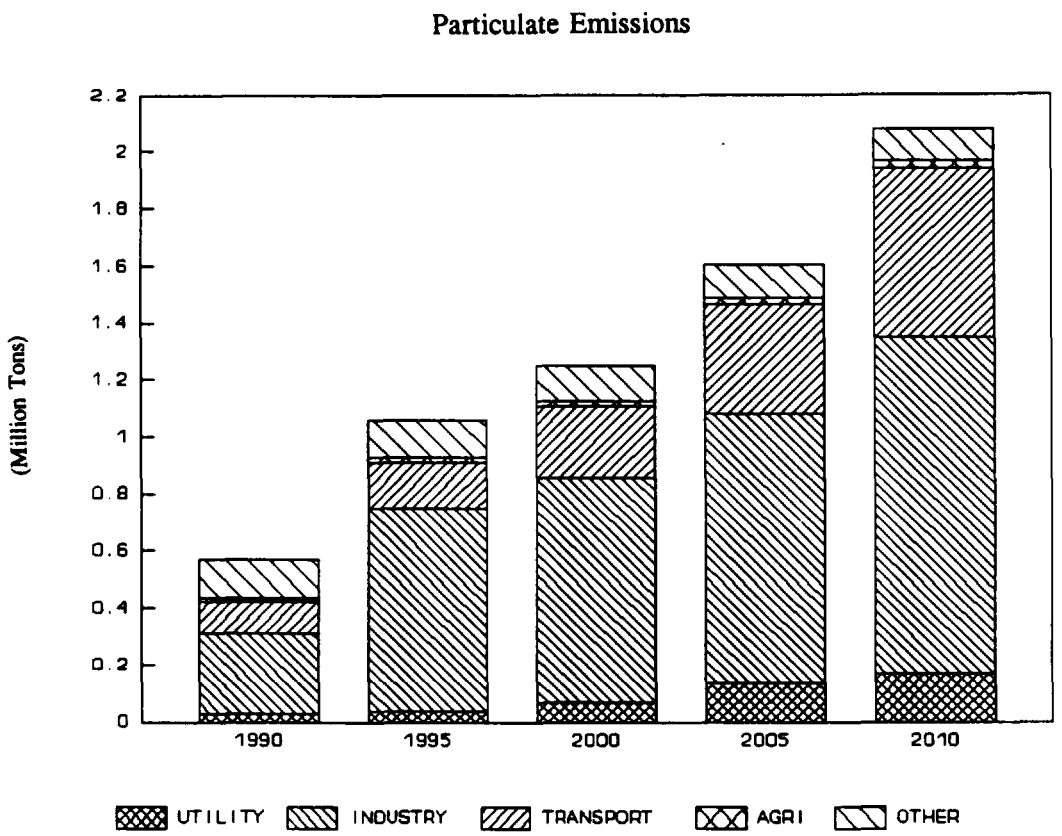
Figure 3: Thailand - PDP Scenario, Current Practices, No-Change Option



Source: Bank mission estimates.

4.33 *NOx*. Based on the model, the transport sector remains the largest contributor of NOx emissions in Thailand over the next two decades. In 1990, transport accounted for 53% of NOx emissions and this percentage increases to 59-61% by the year 2010. Of the transport fuels, the largest contributor to NOx emissions is diesel fuel which contributed an estimated 55% of NOx emissions in 1990 and whose contribution remains roughly the same by the year 2010. Gasoline consumption by the transport sector accounts for roughly 10% of NOx emissions both now and in the future. Under the three scenarios, the power industry contributes between 20-23% of NOx emissions in the year 2010 followed by the industrial sector which accounts for 11-12% of emissions. As with SO_2 emissions, the major implication of the environmental modeling is that NOx emissions increase dramatically under all scenarios, from around half a million tons per year in 1990 to 2.2 million tons in 2010. However, unlike SO_2 or TSP emissions, the dominant factor behind NOx emissions is increased transport fuel use.

Figure 4: Thailand - PDP Scenario, Current Practices, No-Change Option



Source: Bank mission estimates.

4.34 *TSP*. Assuming current TSP control measures for all sectors, particulate emissions increase from a little over half a million tons per year in 1990 to over 2 million tons by the year 2010. There is very little change in TSP emissions according to the different scenarios. This is primarily because such a small percentage of particulate emissions is contributed by the power sector, which is the main focus of the alternative energy scenarios. Based on the model, the industrial sector accounts for 49% of TSP emissions in 1990 and 56-57% in 2010. The transport sector is the second largest contributor of TSP emissions, accounting for 20% of emissions in 1990 and 22% in 2010.

Alternative Pollution-Control Strategies

4.35 The emission scenarios presented above demonstrate the magnitude of air pollution emissions in Thailand if no additional control measures are adopted. Recognizing the seriousness of the situation, particularly SO_2 emissions from power generation, EGAT has announced plans to equip all new lignite- and imported coal-fired power plants with high-efficiency FGD systems. Because of the

high levels of ambient SO_2 concentrations that have been experienced at Mae Moh since 1992, EGAT is also evaluating plans to retrofit existing power plants at Mae Moh with FGD systems.[8/]

4.36 Environmental control costs (both incremental capital and operating costs) should be included in the least-cost energy planning process. For instance, the costs of meeting equivalent TSP emission standards for different types of power plants (e.g., natural gas, coal, lignite, fuel oil, hydro, nuclear) should be included in the capital and operating costs. If there are no emission standards, or the standards are evolving, a range of control costs representing varying levels of pollution control should be included in the model. With the pollution abatement costs included, the model can be run with TSP emissions as a constraint. For any given level of emissions, the model can be optimized to show the set of fuel options which meet all objectives, including environmental ones, at least cost.

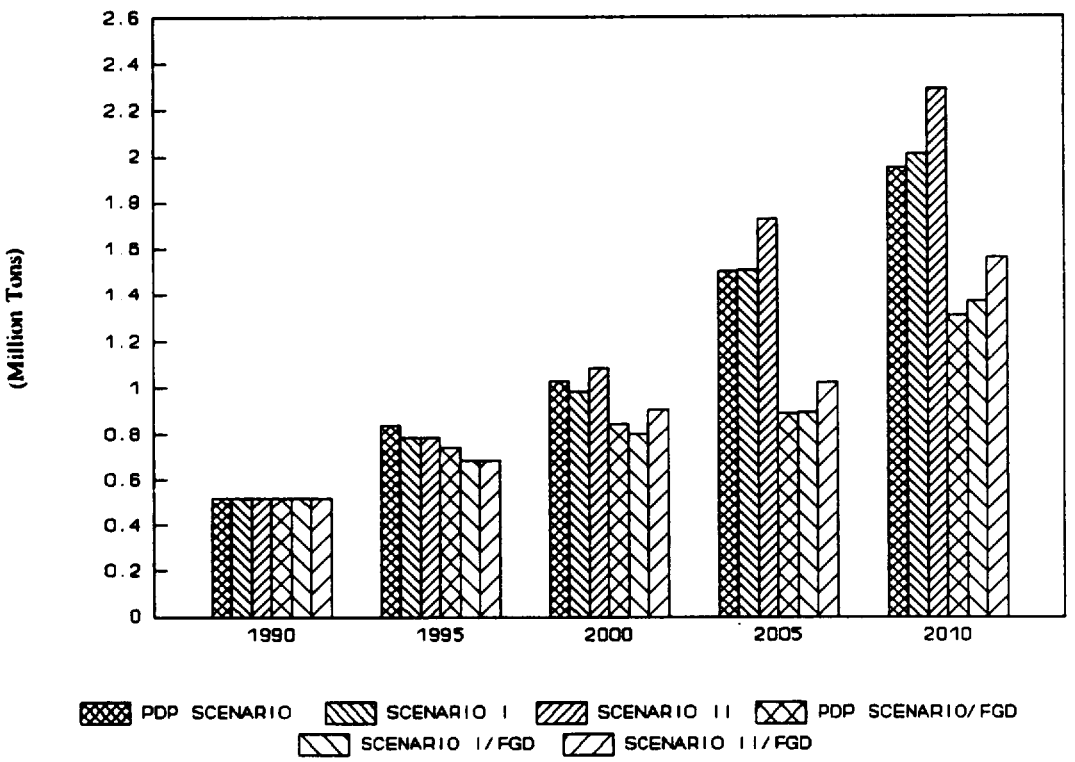
4.37 According to EGAT, the costs of controlling TSP, NOx and SO_2 emissions from power plants are included in their planning model. However, the manner in which environmental costs are handled within EGAT's planning model is not well understood and the operation of the model has not been independently verified for this study.

4.38 ***SO_2 Control Option for New Lignite Plants***. The installation of FGD systems on all new lignite plants was added to the emissions model to gauge the effect on SO_2 emissions. It was assumed that high-efficiency ("wet") FGD systems were installed, and that SO_2 emissions from these plants were reduced by 92.5%. Under EGAT's PDP Scenario, a total of 3300 MW is to be added to lignite-fired capacity between 1995-2005. If FGD is installed on all new capacity (no retrofitting of existing), the percentage of lignite capacity with FGD increases from 23% in 1995, when Mae Moh units 12 and 13 come on line, to 62% in 2005 after 300 MW of fluidized bed combustion at Mae Kham and 2400 MW of capacity at Lampang is added. It should be pointed out that there may be limitations to installing high-efficiency FGD systems on the lignite-fired power plants in Northern Thailand due to a lack of water, particularly during the dry season.

4.39 The installation of high-efficiency FGD on all future lignite-fired power plants was applied to all three energy scenarios. For the PDP Scenario, the effect was a reduction of SO_2 emissions from lignite-fired power plants from 485,000 tons to 384,000 tons in 1995, and from 1.1 million tons to 457,000 tons in 2005. By contrast, estimated actual SO_2 emissions from lignite-fired power plants for 1991 (without FGD) were 440,000 tons. The effect on total SO_2 emissions from the power sector (including emissions from gas, fuel oil and imported coal-fired plants) is compared with the "no FGD" case for all energy scenarios in Figure 5.

8/ At the request of the Government, a mission composed of environmental and health specialists from the U.S. Environmental Protection Agency and the World Health Organization visited the Mae Moh power plants in January 1993 to advise EGAT on short- and longer-term options for reducing SO2 emissions. One of the findings is that for some units there is insufficient space to install high-efficiency FGD systems, while it may be more economic to prematurely retire some of the older units. See, USEPA, "Mission Report: Environmental Action Team to Mae Moh, Lampang Province Thailand, January 10-24, 1993," March 22, 1993.

Figure 5: Thailand - Utility SO_2 Emissions, Pollution Control Option



Source: Bank mission estimates.

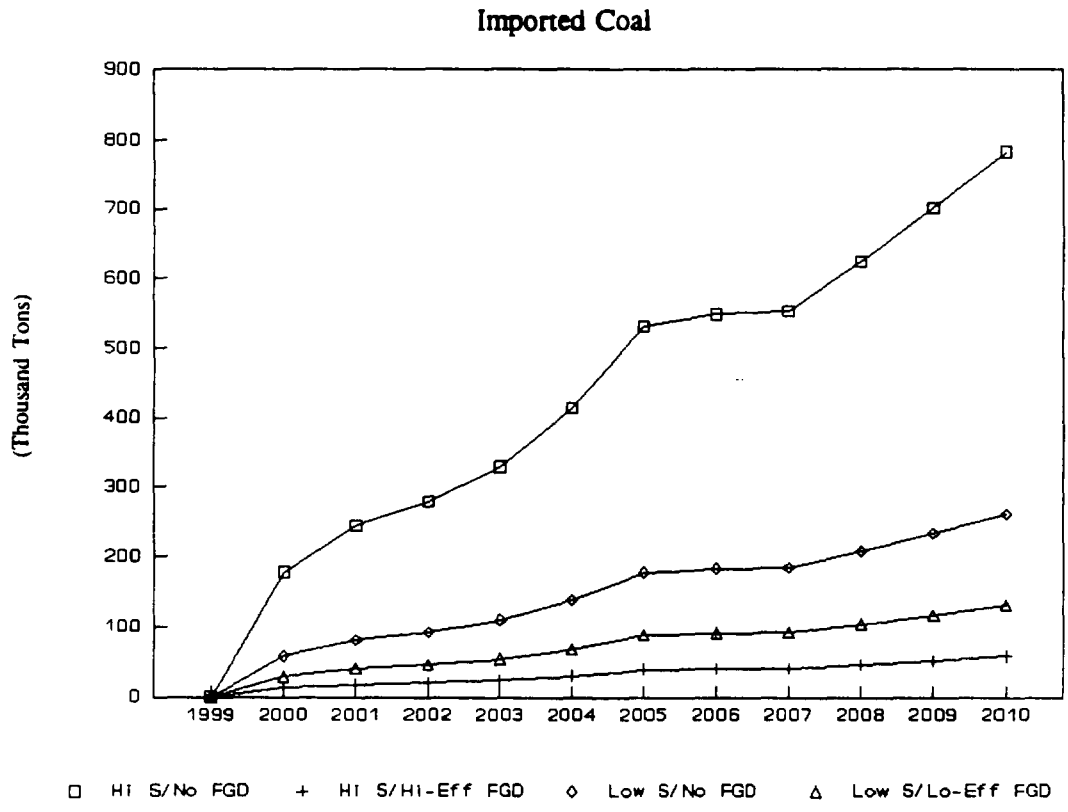
4.40 The costs of installing high-efficiency FGD systems on new lignite-fired plants in Thailand have been estimated based on cost data from EGAT. Accordingly, capital costs are roughly 31% higher with FGD than without, while operating and maintenance costs are 100% higher. At a 10% discount rate, the net present value of installing FGD on 3300 MW of planned lignite-fired capacity is $780 million ($450 m capital, $330 m O&M), or an annualized cost of around $100 million between 1993-2010.

4.41 ***SO_2 Control Options for Imported Coal.*** In the previous section, where no additional pollution control measures were employed, SO_2 emissions from imported coal plants only amounted to 10% of total SO_2 emissions in the year 2010 (PDP Scenario). The reason for this is that EGAT plans to import low sulphur (0.5%) coal, even though the Government has announced plans that high-efficiency FGD systems are to be installed on new coal-fired plants.

4.42 While traditional high-efficiency FGD systems represent one of the most cost-effective ways of reducing the large amount of SO_2 emissions from lignite-fired plants, other options may be more cost-effective with less-polluting fuels such as low sulphur coal. Medium- to low-efficiency FGD

systems can reduce SO_2 emissions by 50-70% with costs that are considerably less than high-efficiency systems. While a high-efficiency FGD system can add 25-30% to the capital costs of a thermal power plant, lower-efficiency systems are in the range of 10% and the costs for many FGD systems have been dropping worldwide as new technologies are developed and commercialized. When combined with improved fuel quality, low-efficiency FGD systems can yield the same SO_2 reduction as high-efficiency systems.

Figure 6: Thailand - Utility SO_2 Emissions, Pollution Control Option



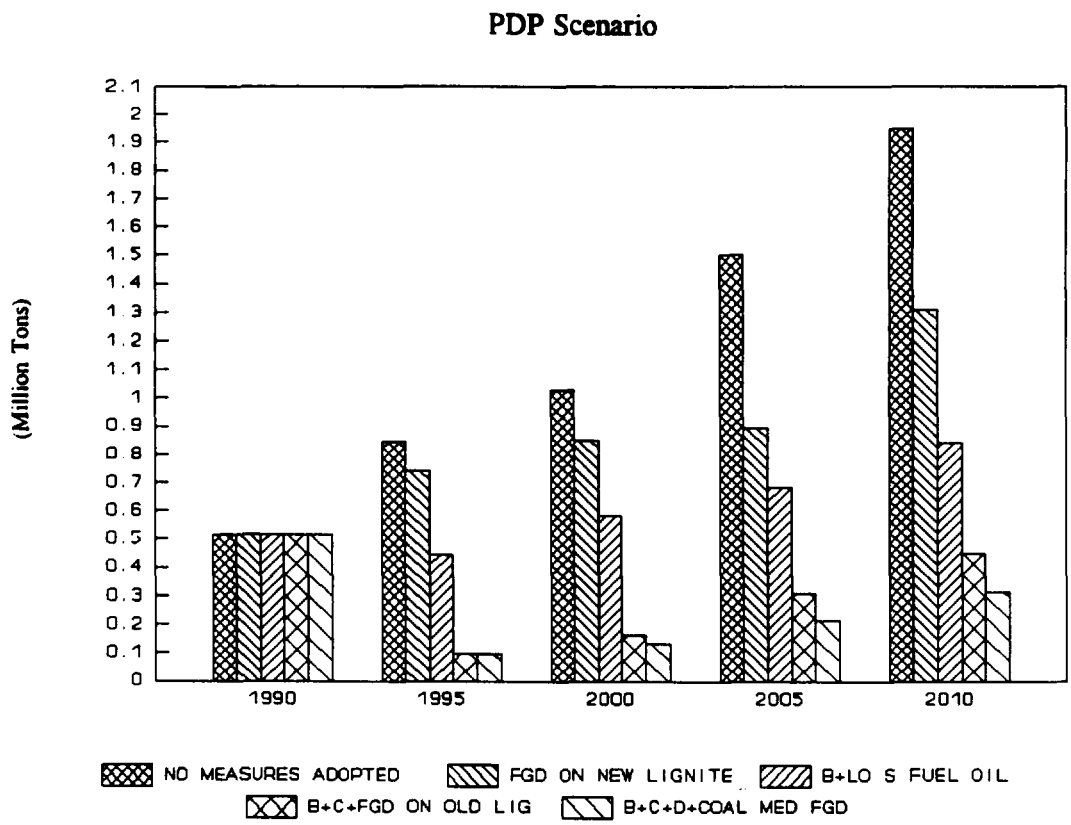
Source: Bank mission estimates.

4.43 Although the measures for improving the quality of domestic lignite are limited, both for technical and economic reasons, a range of coal quality is available on the international market. To assess the effect of varying coal quality on SO_2 emissions, several pollution-control strategies were examined for imported coal. Using the PDP Scenario, both low- and high-sulphur coal and high- and low-efficiency FGD systems were examined in the emissions model. The results of these scenarios on SO_2 emissions are presented in Figure 6.

4.44 The difference between the SO_2 control options for imported coal-fired plants is highlighted when costs are considered. Importing low-sulphur coal carries a premium of around US$58

million per year from the beginning of coal imports in the late 1990s to the year 2010.[9/] The installation of high-efficiency FGD systems on all new coal-fired capacity would cost approximately US$453 million per year. If high efficiency FGD systems are installed, it is probably sufficient to forego the extra expense of importing low-sulphur coal, since emissions will be reduced by 90-95%. By comparison, if low-sulphur coal is combined with low-efficiency FGD, the costs would be around US$167 million per year, or a cost differential of US$364 million per year compared to the high-efficiency FGD case. The change in SO_2 emissions is the difference between the bottom two trend lines in Figure 6. Although not presented in Figure 6, the case of combining low-sulphur coal with high-efficiency FGD results in very low SO_2 emissions and costs of approximately US$511 million per year (Table 4.6).

Figure 7: Thailand - Total Utility SO_2 Emissions, Pollution Control Option



Source: Bank mission estimates.

9/ Assumes a $5/ton premium for low sulfur coal. All values are in present value terms, assuming a discount rate of 10%.

TABLE 4.6: THAILAND - SO_2 Control Options for Imported Coal for Power Generation

Control Strategy	Annualized Cost /a (US$ million)
Low-sulphur (0.5%S) coal	$58
Low-sulphur coal, low-efficiency FGD (50% removal)	$167
High-sulphur (1-1.5%S) coal, high-efficiency FGD (92.5% removal)	$453
Low-sulphur coal, high-efficiency FGD	$511

Source: Bank mission estimates.
/a All costs in present value, at discount rate of 10%/annum.

4.45 ***SO_2 Control Options for Fuel Oil.*** Under the PDP Scenario with no controls, fuel oil accounts for nearly 40% of SO_2 emissions in 2010, with about half the emissions contributed by the power sector. The large contribution of fuel oil to SO_2 emissions is due to the assumption that the power sector will use high-sulphur (3%) fuel oil as is currently the case. If low sulphur (0.5%) fuel oil were used by the power sector instead, SO_2 emissions from fuel oil powered plants would be reduced by more than 80%, or a total of 5.3 million tons between 1993-2010. Assuming a US$6/BBL per barrel premium for low-sulphur fuel oil, it use yields an annual cost of US$136 million. When low-sulphur fuel oil is combined with the policy of installing high-efficiency FGD on new lignite-fired power plants, SO_2 emissions from the power sector are substantially reduced, as shown in Figure 7.

4.46 There are a number of considerations that should be made when comparing alternative pollution control options. These include the relative impact of the emissions, the impact of control measures on power generation costs, and the overall capital requirements of the control measures. In order to compare the costs of various control measures, it is useful to know the per unit costs of reducing emissions. A simple cost-effectiveness analysis has been employed for this purpose which estimates a cost per ton of SO_2 reduced.[10/] (See Table 4.7.) The greatest reduction in SO_2 emissions can be achieved by installing high-efficiency FGD on all new lignite-fired plants, at a cost of $278/ton SO_2. The importation of low sulphur coal (0.5%) is a relatively inexpensive option in terms of cost/ton of SO_2 of $263/ton. Emissions from imported coal-fired plants can be further reduced by the installation of low-efficiency FGD, at a combined cost of around $586/ton. According to the analysis, low-sulphur fuel oil would reduce emissions by some 5.3 millon tons between 1993-2010 at a cost of around $474/ton of SO_2 reduced. By far the most expensive option is the installation of high-efficiency FGD on imported coal-fired power plants. Even assuming lower-cost high-sulphur coal, the high-efficiency FGD option costs $1,493/ton of SO_2 reduced. Table 4.7 provides a summary of alternative control option costs.

10/ The incremental costs of the different control measures have been divided by total sulfur emission reductions to yield a cost per ton of SO_2 reduced. All costs are in net present value, discounted at 10%.

TABLE 4.7: THAILAND - Comparison of Alternative SO_2 Control Options, 1993-2010

TYPE OF FUEL AND CONTROL PLAN	Levelized Cost of Power Generation (US cents per Kwh)	Total Cost of Pollution Control Measure (US$ million, PV at 10% discount rate)	Potential SO_2 Reduction Compared with Worst Case, 1993-2010 (thousand tons)	Cost per ton of Sulphur Reduced ($/ton)
Lignite Emissions with no controls			14,531	
High Efficiency FGD on New Plants (3300 MW)	5.1	$806	7,263	$278
Low Efficiency FGD on New Plants (3300 MW)	4.5	$328	5,038	$155
Retrofit Existing Plants with FGD (2059 MW)	5.0	$948	6,247	$376
Imported Coal Emissions with high-sulphur coal			5,185	
Low Sulphur (0.5%) Coal Imports (27.45 million tons) w/o FGD	5.2	$392	3,456[a]	$263
Low Sulphur Coal Imports with Low Efficiency FGD (12,100 MW)	5.6	$1,135	4,494[a]	$586
High Sulphur (1.5%) Coal Imports with High Efficiency FGD	5.7	$3,086	4,796[a]	$1,493
High Sulphur Coal Imports with Low Efficiency FGD	5.2	$743	3,111[a]	$554
Fuel Oil Emissions with high-sulphur (3%) fuel oil			6,399	
Low Sulphur (0.5%) Fuel Oil w/o FGD	5.8	$1,090	5,333[b]	$474
Natural Gas	4.0	--	2,477[c]	--

Source: Bank mission estimates.
(a) Compared with high-sulphur imported coal (1-1.5%), no controls.
(b) Compared with high-sulphur (3%) fuel oil.
(c) Difference in utility SO_2 emissions under the High- and Low-gas Scenarios (see text).

E. Implications and Conclusions

4.47 The environmental analysis of Thailand's fuel supply options shows that emissions of SO_2, NOx and TSP will increase significantly over the next two decades unless additional measures are taken to control emissions. The Government has undertaken or is considering a variety of measures to reduce emissions, particularly those of SO_2. These include the installation of FGD on all new units at Mae Moh and on the existing units 8-11; reducing the sulphur content of fuel oil and plans to import low-sulphur coal for power generation and the installation of FGD on such plants. The Seventh plan has a target for SO_2 emissions of 860,000 tons in 1996. While these and other measures would reduce

SO_2 emissions below what is projected under the base case scenario, the foregoing exercise demonstrates the severity of the air pollution problem if no action is taken. As the model shows, even for emissions which are already subject to fairly strict environmental controls, such as TSP from the power sector, the absolute level of emissions is likely to increase substantially by the year 2010.

4.48 Because the environmental impacts of energy use in Thailand will become even more important in the future, and the costs associated with environmental mitigation will be large, it is essential that environmental mitigation costs be included in the least-cost planning of EGAT and other energy agencies. By including the mitigation costs (to a common standard) of each fuel supply options at the beginning, a different set of supply options would likely be chosen as part of the least-cost plan. By contrast, the analysis here has attempted to mitigate environmental costs after the fuel supply choice has been made. As noted in the previous section, the manner in which environmental control costs are included in EGAT's planning model is not known in detail. However, when environmental costs are included in the least-cost energy plan, the value of clean fuels will increase while the value of dirtier fuels will decrease.

Power Sector

4.49 Given the dominant role that EGAT's energy demand scenarios play in this study, the environmental implications for the power sector have been highlighted. Based on the analysis, it is apparent that the control of sulphur emissions must be a central aim of environmental policy for Thailand's power industry. The seriousness of the problem is illustrated in the simulations of SO_2 for the historical period 1982-1991. To keep SO_2 emissions in Thailand at 1990 levels, sulphur emissions would need to be reduced by 40% in 1995, 50% in 2000, 66% in 1995, and 75% in 2010. As the need to control SO_2 emissions increases, the value of natural gas will increase. Natural gas is also much cleaner than lignite, coal, and oil in terms of particulate emissions. Despite the environmental benefits of using natural gas, the analysis of alternative energy supply scenarios demonstrates that fuel switching alone will probably not be sufficient for reducing future SO_2 emissions. The High Gas scenario results in about 10% less SO_2 emissions in both 2005 and 2010 than under the Low Gas scenario. Nevertheless, the environmental gains that can be made by using natural gas are very low-cost and should be fully exploited.

4.50 ***Lignite***. If they are not already, the costs of controlling SO_2 emissions should be included in EGAT's planning model. In addition, until national emission standards are adopted, a range of control levels and associated costs should be used in order to minimize costs. The main conclusion is that high-efficiency FGD systems should probably be installed on all new lignite-fired plants, given the large amount of sulphur that would otherwise be emitted. It should be pointed out that water shortages in Northern Thailand may limit the ability of installing traditional "wet" FGD systems or may require higher costs. Since EGAT is currently forced to reduce operation at its existing lignite-fired power plants at Mae Moh, it is clear that retrofitting of some existing units is also required to reduce current SO_2 emissions to acceptable levels.

4.51 ***Fuel Oil***. According to the emissions model, fuel oil remains a significant contributor of SO_2 emissions from the power sector over the next two decades. This is because of the importance of fuel oil as a "swing" fuel for Thailand's power sector, and because the model has assumed the use of high sulphur fuel oil as the baseline estimate for the purpose of emissions. By switching to low-sulphur fuel oil in the power sector, which is the trend in Thailand's transportation sector, significant reductions

in SO_2 emissions can be achieved. For the purpose of these analyses, the low sulphur (0.5%) fuel oil has been used to integrate the environmental mitigation costs in future.

4.52 ***Imported Coal.*** The analysis shows that there are a number of ways to control SO_2 emissions from new thermal power plants fueled with imported coal. The import of low-sulphur coal is perhaps the easiest and least-cost way of limiting SO_2 emissions from new coal-fired plants. Based on discussions with EGAT, it has been assumed that imported coal-fired plants will use low-sulphur coal. If this is the case, overall sulphur emissions from coal-fired power plants will account for less than 10% of Thailand's total SO_2 emissions; the main sources of SO_2 will be domestic lignite and fuel oil, if the latter continues to be of the high sulphur type. Since Thailand's SO_2 standards will likely become more stringent in the future, the low-sulphur coal option may be insufficient to reduce emissions to acceptable standards. Instead of installing high-efficiency FGD on all new coal-fired plants, which will be very expensive, EGAT and the Government should explore the option of importing low-sulphur coal and installing low- to medium-efficiency FGD systems (50-70% reduction) which are increasingly commercially available and whose costs have been steadily dropping.

4.53 Compared to the industrial and transport sectors, power utilities will not contribute a major percentage of NOx or TSP emissions in the future. Nonetheless, the absolute level of emissions will be high. For instance, the absolute level of NOx emissions from the power sector in 2010 will be nearly as large as total NOx emissions for Thailand in 1990. A similar, though less dramatic, trend is exhibited for TSP emissions. In the year 2010, TSP emissions from the power sector will increase five-fold even if the current level of particulate control in the power sector is maintained in the future.

Transport

4.54 Although a detailed analysis of transport-related air pollution is beyond the scope of this report (see Bank Report No. 11770-TH), several trends are clearly observable from the emissions model. First, the transport sector, principally diesel vehicles, are responsible for the majority of NOx emissions in Thailand. This trend is observable both for the historical period and for future emissions. In addition, the model predicts that TSP emissions from the transport sector will increase from 110,000 thousand tons in 1990 to 503,000 tons in 2010, unless additional measures are taken to control transport emissions.

Industry

4.55 The model predicts that future TSP emissions from the industrial sector will be large both in percentage and in absolute terms, due largely to the growth of coal and lignite consumption. Without additional TSP controls or fuel switching policies, TSP emissions will increase nearly five-fold by the industrial sector over the next two decades; lignite consumption accounts for 62% of emissions in the year 2010.

4.56 A secondary consideration for the industrial sector is SO_2 emissions. If the Government's plan to reduce SO_2 emissions from the power sector are carried out, the industrial sector will become the largest contributor of SO_2 emissions. The model predicts that industrial SO_2 emissions in 2010 will be 25% higher than Thailand's total SO_2 emissions in 1990. This is likely to create serious environmental problems since industries are usually located closer to populated areas.

4.57 Many of the options for controlling SO_2 emissions from the power sector are also applicable to the industrial sector. Low sulphur fuels, including fuel oil, imported coal, and natural gas, are a relatively easy way of reducing SO_2 emissions in Thai industry, particularly for numerous small-scale firms, where the installation of FGD or other technologies would not be cost-effective. Industrial consumption of lignite, 70% of which was consumed by the cement industry in 1991, is more appropriate for the adoption of sulphur-removal systems. Again, low- to medium-efficiency systems can be significantly less expensive than high-efficiency systems and should be examined.

F. Integration of Environmental Costs

4.58 The study has incorporated the cost of a number of measures for reducing atmospheric emissions which will be needed in Thailand to meet environmental standards. The integration of environmental costs has taken place at two stages in the analysis. First, in the industrial sector, projections of final energy demand by fuel type (where the end-use application was not a constraint), were made using higher fuel and mitigation costs. Specifically, the price of lignite includes the costs of sulphur control for all future cement plants; the prices of imported coal and oil are based on the use of low sulphur (0.5%) coal and low sulphur (0.5%) fuel oil in all industrial applications. The costs of reducing atmospheric emissions was also incorporated into the choice of fuel for the power sector. In this stage of analysis, issues unique to the power sector were considered, such as the mix of plant types in EGAT's present system, EGAT's existing projects and future plans for plant retirement. It was assumed that future lignite-fueled power plants would use high-efficiency FGDs (at a cost which would be about 28%-30% higher than the base case). For existing plants, the analysis included the costs of retrofitting, which is based on EGAT's statements that Mae Moh units 8-11 will be fitted with FGDs, and that an analysis is being made for retrofitting units 4-7. Other steam plants are assumed to use low sulphur coal with medium efficiency FGD and low sulphur fuel oil without FGD. In the residential and commercial sectors, non-commercial fuels are assumed to decline while there are no serious direct emissions associated with other competing fuels; LPG and electricity.

CHAPTER V

INSTITUTIONS

5.1 The institutions in Thailand's energy sector are mature, and their inter- and intra-sectoral arrangements are quite sophisticated. The policy framework is extensive and the energy related agencies are numerous; they spread across many ministries and include several cabinet level committees. The relationships between Government energy agencies and state energy enterprises are increasingly similar to those of other advanced East Asian countries; the agencies formulate energy policies in line with the enterprises' commercial objectives, yet these are consistent with the country's needs. This contrasts with many other developing countries where the state enterprises' organizational objectives and operations are defined in the context of Government policies. The annex provides an organizational chart of Thailand's energy sector.

5.2 The organizational aspects of the energy sector were reviewed for this study in order to assess the institutional qualities and arrangements needed to sustain the recommended supply options. The assessment was carried out from two perspectives. One reviewed the state energy enterprises that presently supply energy to the economy. The objective was to broadly determine whether they could (a) supply energy to the economy efficiently, (b) perform as efficiently if their present operations were expanded but the modes of operation remained the same (i.e., PTT would be required to supply more imported or domestic gas, and EGAT would be required to supply more imported-coal-based power) and (c) perform efficiently in the event the operating modes would be changed (i.e., PTT would be required to supply LNG). The assessment was not intended to establish whether the state energy enterprises should be made responsible for implementing the recommended supply options. Rather, it was to determine if they have the capability to carry out the tasks, in the event the present organizational structure of the sector would continue.

5.3 The second perspective was to determine if the Government agencies involved adequately meet the institutional needs of the energy sector and the state enterprises. The evaluation looked into the agencies' functions and roles, their inter-governmental relations, the degree of autonomy which they offered to state enterprises, and the changes the agencies need to make to accommodate the new supply regime. The following paragraphs discuss both perspectives and the issues and options involved.

A. State Energy Enterprises

5.4 The two enterprises reviewed were PTT and EGAT. PTT is the state company involved in downstream oil and gas activities (upstream activities are carried out by the private sector). EGAT is the state company involved in generating electricity and producing and utilizing domestic coal (lignite).[1/] The potential new energy sources, such as LNG and nuclear, are discussed in paras. 3.39 and 3.67, and their institutional requirements are evaluated, along with the capacity of existing energy enterprises to deal with these.

1/ It was decided that the institutional review would not assess the role of the Metropolitan Electricity Authority (MEA) and Provincial Electricity Authority (PEA), which are responsible for distributing power in the Bangkok metropolitan and provincial areas, because these two are not the primary suppliers of energy.

5.5 With respect to the hydrocarbon (oil and gas) sector, the prominent player is the Petroleum Authority of Thailand (PTT), whose governor reports to the Permanent Secretary of the Ministry of Industry. Thailand's hydrocarbon resources are produced either totally by the private sector or through a joint venture between the private sector and PTTEP, which is a subsidiary of PTT. In the latter case, the private sector is the major shareholder and has included major international oil companies such as Unocal, Shell, Esso, Total and British Gas, (para. 3.14). PTT is responsible for the primary transportation of gas and oil in the country (Thailand has very little indigenous oil). It sells gas to EGAT, and only a small quantity to industry. Therefore, it is also the distributor of gas in the country. In distributing and marketing oil, however, PTT competes with international oil companies, having a one-third share of the market. The other two-thirds are shared among Caltex, Shell and smaller firms.

5.6 Thailand's three existing refineries are either privately owned (Esso refinery), or owned through joint ventures between the private sector and PTT (PTT owns 30% and 49% of Bangchok and Thai Oil refineries). Thailand is currently constructing two new refineries, with majority shares owned by Caltex and Shell.

5.7 PTT has about 4,000 employees and its annual revenue is about US$3.5 billion. Its investments between 1992-1996 will be about US$2-US$3 billion. It is a well-run enterprise capable of managing the substantial growth in investment, exploration, production and sales. While some major decisions are made at the Government level, PTT enjoys full autonomy with regard to its day-to-day operations. Two years ago, PTT was reorganized on a profit-loss basis with four separate business units (oil, gas, petrochemicals and services) that function autonomously. This reorganization is an interim step to take PTT through two or three years of commercial operations and lead to the organization's corporatization and eventual privatization (in which case the business units might be sold separately to public). The Bank, through its forthcoming investment operation, will review the recommendations of an on-going study which is evaluating PTT's privatization options; these range from selling equity (on PTT) as a whole, selling all or part of the subsidiaries, or entering into joint venture agreements with respect to its business units.

5.8 Based on the review of PTT's organization and its operational efficiency, as well as its commercial philosophy with respect to its future course, it is expected that PTT will be fully able to continue performing its present functions of supplying oil and gas to the economy efficiently and reliably; also, that it will have no difficulty performing equally well in the event its activities expand, such as with the import of gas from Malaysia or Myanmar. On the organizational side, the information flow, delegation of responsibility and overall management in key areas such as finances, accounting, auditing, human resources (training), planning and management information (MIS), are effective, as are the control and communication procedures among the company's various levels. Its planned investment program (including joint ventures, acquisitions and mergers, in both domestic and international markets), is quite rational. With regard to operations, PTT has considerable experience. It has constructed and operated oil and gas pipelines, refineries, petrochemical and gas plants, and sold and bought oil, gas and petrochemical products. Therefore, from an institutional point of view, PTT is capable of conducting all aspects of hydrocarbon business, including development, production and utilization of oil and gas under any of the proposed scenarios.

5.9 EGAT is also a very well-run and efficient organization[2/]. Since its establishment about 25 years ago, it has grown to a staff of 32,000 with US$2 billion in annual revenues. As of the end of 1991, it had an installed capacity of 8,000 MW and generated 50,000 GWh of electricity (para. 2.15). It runs conventional thermal plants (56%), hydro (29%), and combined-cycle (12%) plants. It also imports power (from Laos) and is involved in the engineering and construction of hydro plants. In addition, under its Lignite Mine Directorate, EGAT operates the Mae Moh and Krabi lignite mines, producing and utilizing 3,000 ktoe per year of lignite for power generation. As with PTT, EGAT is devising plans for deregulation, restructuring and privatization to promote a larger private sector role in power development. From 1993-1995, this will involve (a) deregulating and corporatizing EGAT, including the sale of EGAT equity on the security market; (b) selling 51% of the Electricity Generating Company (EGCO), an EGAT subsidiary created in 1992; [3/] (c) soliciting build-own-operate (BOO) proposals for new generating plants through an open competition among independent power producers and EGCO; and (d) incorporating MEA and PEA, and increasing PEA's regionalization, to prepare for privatization. These measures will affect the fuel option needs and decisions to the extent that the private sector will have greater freedom to make investment and pricing decisions, as well as mobilize new financial resources.[4/] However, EGAT, as the bulk supplier of electricity, from an institutional point of view, also would have no difficulty generating or importing additional power, and utilizing domestic and imported coal.

5.10 While some of the state enterprises in Thailand still lack financial discipline and autonomy or suffer from labor redundancy and cumbersome personnel policies, this is not the case with either PTT or EGAT. Further, both are seriously considering a major restructuring of their organizations (in form of corporatization, partial or full privatization) --and for both this is only a question of time. In the interim, however, as utilities that supply energy, their public status does not hinder their performance. Except for nuclear energy, for which the institutional aspects are quite different (para. 3.67), they can handle all other types of commercial energy supply, including LNG. Two actions, however, are encouraged. The Government needs to amend the acts creating PTT and EGAT, providing them the latitude to expand their business activities and strategic planning, which would include the freedom to diversify their financial portfolios. Also, the present on-lending arrangement between the Government and the entities --in which the Government does not charge them a fee-- needs to be re-examined, so the entities can operate on a commercial basis.

5.11 Still, the handling of various supply options proposed here need not be limited to these two entities; instead, it is quite possible that LNG could be handled by a different entity, or that the import of gas or even the transport of domestic gas could also be conducted by other entities. Given that the objectives of this study are to recommend viable supply options and examine the institutional and legal framework to the extent it may create obstacles to implementing the recommended option (be it private or public institutions), the study concludes that both PTT and EGAT have the managerial and operational capabilities to supply commercial energy in any form and mode, except nuclear.

2/ Under one of the Bank's operations (loan 3138-TH), EGAT's cost effectiveness and operation were reviewed and found to be viable.

3/ EGCO owns and operates some of EGAT's generating plants and sells power to EGAT.

4/ A key issue will be whether EGAT's power development program (PDP) will remain a mandatory investment plan for both public and private investors, or simply an indicative one.

Nonetheless, it also concludes (para. 6.32) that the size of the investment required to finance the energy projects needed to meet the country's energy demand in the next decade or two, calls for a large volume of capital. It is this factor which would drive the entities towards restructuring their institutions as corporatized or privatized structures. This is discussed in Section VI.

B. Governmental Energy Organizations

5.12 The key governmental organizations involved in energy affairs are: at the highest level, the National Energy Policy Council (NEPC), which is chaired by the Prime Minister, and whose members include deputy prime ministers and those ministers whose portfolios involve energy, as well as representatives from the National Economic and Social Development Board (NESDB), the secretary general of National Energy Policy Office (NEPO), the director general of the Energy Development and Promotion Department (EDPD) and the director of the Budget Bureau. On behalf of the cabinet, it approves major policy changes, plans and projects in the energy sector and defines roles, functions and priorities of the various ministries and state enterprises in the sector. Also, it oversees two committees: the energy policy committee (which, in turn, is made up of petroleum policy, electricity policy, and energy conservation and alternate energy committees), and the energy conservation promotion fund committee.

5.13 The National Energy Policy Office (NEPO), which is the secretariat to NEPC, acts as an operating arm to the Council (the Annex provides an organizational chart of NEPO). NEPO functions primarily as a link between NEPC and the country's state energy enterprises and has a three-pronged role. First, it formulates NEPC directives and disseminates them in form of policy among the state energy enterprises and Government agencies (this function also includes a degree of ad hoc regulation). Second, it formulates commercial and operational requirements of the state energy enterprises and the energy-related needs of other Government agencies, into a policy-based framework for NEPC's consideration. Last, it coordinates activities among the state energy enterprises as well as between the enterprises and Government agencies. NEPO plays a pivotal role in formulating the energy sector policy as well as providing coordination and advisory functions (para. 5.18).

5.14 NESDB is a central planning agency that assesses the country's economy and prepares the five-year plans. In the energy sector, it is responsible for recommending to the council of ministers whether to approve or reject major energy projects.

5.15 The Department of Mineral Resources (DMR), whose Director General reports to the Permanent Secretary of the Ministry of Industry, is responsible for assessing the county's coal and petroleum reserves, as well as the preliminary exploration of coal and petroleum. Two of its important functions are to grant concession licenses for exploration and mining, and supervise the various exploration and production activities (including the monitoring of their environmental impacts). DMR is also the secretariat for the Thailand-Malaysia joint development areas (JDA). However, because the responsibilities of DMR are beyond the staff's level of expertise, it is recommended it be strengthened in certain key areas (assessing reserves and explorations, and analyzing the country's fiscal regime in the context of the economics of gas utilization).

5.16 The Department of Energy Development and Promotion (DEDP), which is a recent establishment, assumed the responsibilities of the now-defunct National Energy Administration (NEA). DEDP is under the Ministry of Science, Technology and Environment (MSTE). The NEA was responsible for developing non-conventional energy sources. Further, NEA theoretically also shared policy formulation responsibilities with NEPO. In practice, however, NEPO conducted all policy work. Presently, DEDP's responsibilities are limited to conducting research and development and also to monitor energy sector activities (the policy formulation responsibility has been formally assigned to NEPO). This delineation of responsibilities was instituted with the intent of placing supervision and evaluation activities within one agency (DEDP). DEDP and the Energy Conservation Center of Thailand (ECCT) both report to the Minster of Science and Technology.

5.17 The Department of Industrial Works (DIW) has the principal responsibility for controlling industrial air and water pollution. It controls all industrial users of coal (except EGAT), sets specific emission standards, reviews the environmental impact assessments and monitors and enforces the industry mitigation plan.

C. Policy Framework

5.18 As discussed above, Thailand has developed an extensive policy framework over the last 40 years in the energy sector. The sector's guidelines are provided in the National Energy Policy plans, which, in turn, are integrated in the National Five-Year Plan, the seventh of which began in October 1991 and expires in September 1996. The Government's primary objective is to enhance sector efficiency by establishing institutional arrangements that would minimize the need for public sector investment, increase cost-effective operations, optimize the use of domestic resources, and promote and provide incentives for a profit-based commercial operation. The Government has pursued these objectives with conviction, and the result, particularly with regard to revenue-generating entities such as EGAT and PTT, has been quite impressive. At the Government level, however, there are two key issues. One is the need to strengthen NEPO, which is an effective central body that could provide overall sector coordination and coherent sector strategy, and the second is the need for a regulatory framework for energy affairs. These matters are discussed below.

5.19 NEPO was established in 1986 in response to the need for a high level entity to formulate, coordinate and advise on energy matters. Prior to establishing NEPO, there was no coordination of energy affairs. NEPO has carried out these responsibilities efficiently and responsively, which was the reason it was elevated to departmental status in 1992. Further, the exclusive responsibility for energy policy formulation and implementation was formally transferred to NEPO, making it the sole agency responsible for energy policy affairs. As the result, NEPO's budget was increased to enable it to enlarge its organization, increasing its staff from 20 to 50, and eventually to 80. The new organization consists of four policy divisions and the office of the secretary. The Petroleum Division is responsible for policy on exploration and development and pricing of hydrocarbon. The Electricity Division is responsible for load forecasting, generation and distribution, and electricity economics. The Energy Policy and Planning Division is responsible for policy and planning, energy analysis and forecasting and energy information. The Energy Conservation and Alternative Energy Division --which also includes the Energy Conservation Promotion Fund-- is responsible for affairs related to renewable energy and energy conservation. However, as energy issues become more complicated, the number of NEPO's

staff and the level of their expertise need to be increased to meet the new demands. In this connection, two new issues arise: The first is whether NEPO is able to recruit the required number of qualified staff in a timely manner, given the relatively large difference in the salary scale between the public and private sector. The second is the need for training of NEPO staff in a variety of fields such as economic pricing, international oil and gas markets, load forecasting, LNG and nuclear matter, as well as the need for NEPO's institution building (which would include a management information system).

D. Regulatory Framework

5.20 Thailand currently does not have an independent regulatory body nor does the present regulatory framework (administered by NEPO), have adequate scope to govern the prices, investment and entry and exit rules of the sector in a comprehensive form. While regulations are intended to enhance a sector's efficiency (to compensate for market failures), the lack of regulations does not imply inefficiency in sector performance. Therefore, the establishment of a regulatory framework should not be considered a pre-requisite to an optimum operation. In fact, presence of adequate competition would be the most effective regulator.

5.21 In case of Thailand, however, the need for sector regulation is not driven by inefficiency, but to bring in private capital to finance the massive investment required for the country's growing energy demand. As discussed in para. 6.32, the public sector alone cannot, and should not, carry out the burden of such a huge undertaking. To induce private entities to invest in the sector, a set of legally binding, transparent, fair and practical rules and regulations are needed in order to assure them that their investment and future income and market entry and exit are predictable.

5.22 This study does not intend to provide a detailed analysis of the regulatory framework needed, nor an analysis of what to regulate or the shape of the regulatory institution; lacking information about the eventual structure of the sector organizations, such a detailed analysis would not be meaningful. If, for example, the organization of the sector remains unchanged, and EGAT and PTT continue to be wholly Government owned, it could be argued that the limited regulatory process presently administered by NEPO, is adequate, and that, barring the issue of the increased private sector participation, the process is responsive to the needs of the sector under Thailand's current energy supply and demand profile. This is particularly valid, since regulations involving safety and environmental protection (to the extent that such regulations exist and are being carried out), are part of a broader set of rules governing the country's other industrial and commercial activities. (NEPO therefore, would only have to administer the economic regulation, which mainly involves the prices of energy products).

5.23 But, as discussed earlier, since the need for an independent regulatory framework in Thailand is driven by the need for new sources of private funds, the decision on establishing such a regulator should be made as soon as the decision on the restructuring of the sector is taken. In fact, the regulatory framework should be fully in place by the time Thailand actively seeks to increase private capital: When private investors evaluate the market value of the energy entities, or a particular project in the sector, the value would be enhanced considerably by the existence of a cohesive and acceptable set of rules. Additionally, the regulator would become part of the process in preparing and promoting the proposed sale.

5.24 Although the decisions regrading the restructuring of the sector have not been taken and the necessary regulatory framework can therefore not be properly designed, it is expected that certain regulatory features would be desirable --based on Thailand's unique energy supply and demand condition. Thus, it is recommended that the Government prepare the ground for establishing an independent regulatory framework, taking into account the following features.

5.25 The oil sub-sector in Thailand is heavily privatized and operates within a competitive market. The upstream gas sector activities are also carried out by private sector and this is expected to continue. However, PTT transmits and distributes gas on a monopoly basis (EGAT consumes over 95% of gas, hence the distribution is limited to one single consumer). Similarly, power generation, transmission and distribution are carried out by national monopolies (EGAT, MEA, and PEA). Coal is primarily produced by EGAT; therefore, the regulatory framework that would govern the electricity subsector, could also govern the coal subsector. Hence, gas transmission and the electricity sector which are now state controlled would certainly benefit from regulation that would mitigate their monopoly position.

5.26 A regulatory framework for the transmission and distribution of gas is warranted for several reasons: (a) PTT presently decides on the quantity of gas taken from each producer, and this has an important bearing on the price of gas delivered to consumers (if the present pipeline system needs to be converted to "common carrier" status, there is no regulatory framework in place for such an operation); (b) PTT presently sells about 90% of its gas to EGAT and the balance to industry, a proportion which could change both at PTT's and EGAT's discretion; hence this affects the gas market and possibly the market for other fuels, as well; (c) there is no uniformity in the formulation and application of gas safety standards and regulations applied to all gas production and utilization in the country and (d) there is no mechanism for monitoring the equity aspect of the gas price and the quality of service offered by PTT.

5.27 While the rationale for a regulatory framework in the electricity subsector is different, the principles with respect to efficiency, safety and equity are the same as for the gas industry. In fact, the issue of whether there should be two separate agencies for the gas and electricity or if they should be combined into one, must be analyzed in detail. A single regulatory agency offers the advantage of developing coherent policies and consistency in applying regulation. On the other hand, two separate bodies can pay greater attention to the constituents' needs and focus better on sub-sector issues. In either case, the two fundamental features of the regulatory body are independents and transparency of actions.

5.28 To be independent, the utility regulator must be separate from any political or other special interest. This implies the regulator's actions should not be subject to ministerial approval, that the regulations should be changed only by due process, and that the regulatory body should be free to appoint its own staff and recover its own costs through fees levied on the industry. With respect to efficiency and equity in the regulating agency's actions and decisions, transparency is crucial, particularly for attracting private sector participation. This can be developed through a variety of actions ranging from holding public hearings, publishing regulatory orders and decisions and, in particular, providing the public with a detailed analysis and evaluation of the decisions made.

5.29 As discussed in para. 5.27, the regulatory framework for the energy sector involves two substantially different areas: economic and commercial regulations, which address issues such as pricing, investment, rate of return, and the rules for market entry and exit; and technical regulations,

which address issues such as safety, the environment (including codes and standards for safety and environmental protection), and the quality of service. Although the two types should be clearly coordinated, they require different expertise.

5.30 However, before a regulatory framework can be introduced, comprehensive gas and electricity legislation is needed (hence, the need for some revision in PTT's and EGAT's current acts), to serve as the basis on which regulations, standards and codes of practice can be established.

CHAPTER VI

OPTION EVALUATION AND PROPOSED STRATEGY

A. Ranking of Supply Options

6.1 The preceding analyses, using end-use constraints and economic and environmental costs (total costs), resulted in a projection for individual fuels required in different time periods over the next two decades: The transport and agriculture sectors only consume oil (see para. 3.49, for possible use of CNG in transport); the residential and commercial sectors are expected to consume LPG and electricity; and industry's choice is partly dictated by the end-use application. Therefore, the decision with regard to the natural gas, lignite, coal or oil (assuming insignificant hydro power supply), will affect only about 40%-50% of the total primary energy requirements; those in industry (that part which is not constrained by the end-use application) and in power sector. In allocating the appropriate fuels for the industrial and power sectors, their economic costs and their availability were considered in order to arrive at a final matrix for the fuel-mix.

6.2 To find an effective supply strategy to meet the projected demand, all commercial supply options were examined. Those clearly representing a non-viable option, such as nuclear, were eliminated. For those remaining, they were ranked according to their total economic costs. The following is the ranking of various options according to their economics.

6.3 ***DSM***. Over the broad spectrum of the fuel supply options, the least-cost means of supplying (saving) energy is with the on-going demand-side management (DSM) program. Considering the program's cost (US$188 million) and the capacity and energy it will save from 1992-1996 (225 MW and 1,400 GWh per year), the unit cost of additional supply it will provide would be only US¢2.1 per kWh. However, this additional supply, or saving, represents less than 4% of the total expansion needs of the power sector during the period. Assuming the program will be successfully implemented and that its scope will subsequently be increased, the total capacity saving expected during the planning period is 2000-3000 MW, or about 10% of the power sector expansion needs. Hence, this course is limited.

6.4 ***Hydropower***. Hydroelectricity import from Laos (through the proposed Nam Theun projects), which is estimated to cost about US¢2.6 per kwh, represents the second most attractive option. If implemented, it would meet about 3%-5% of the Thailand's energy needs at a cost which is about half of the next best source (domestic gas). For this reason, two low-cost projects have been identified (Nam Theun 1/2 and 2), which could be completed by the start of the next decade. To ensure this, negotiations with Laos should begin soon. At first, they should be oriented towards a preliminary power trade agreement between the two countries; subsequently, they should explore the possibility of a joint-venture to finance the Nam Theun projects (either through EGAT or through Thai private sector participation), and consider schemes such as BOT. Such a joint venture would greatly facilitate the project because it would help mobilize funds (a major source of concern for Laos), and also provide assurances to that country about Thailand's long-term commitment to sustain the project.

6.5 However, Laos' two hydro projects would also be limited because the total energy they can supply would not be more than about 800 MW; and, other potential hydro projects in Laos (or

other sites in the mainstream Mekong River or its tributaries) are not expected to fall within the planning period (para. 3.56). Further, for the purpose of this study, no hydro sites within Thailand have been considered feasible (para. 3.55). This assessment is consistent with EGAT's projection, which assumes that the hydro share of total primary energy will remain fairly constant (at current levels of 4%-7%) during the planning period. Hence, Thailand must still search for additional sources of energy.[1/]

6.6 ***Natural gas***. The third most attractive option for Thailand is domestic gas. However, the ranking of both domestic and imported gas among the supply options must consider the economic costs of supply and opportunity value of gas. Economic costs should include the depletion premium, as well as the costs to develop, produce and transmit gas to the consuming centers. However, the issue of depletion premium (the future opportunity costs of presently produced gas), is somewhat arbitrary because its calculation involves a variety of assumptions such as the replacement fuel at the margin, the switching time in the future (which itself is a function of the country's internal consumption and potential export), the proper determination of gas reserves, the projected price of different fuels, and the discount rate. These assumptions could vary widely, particularly where they relate to export-import conditions, and the depletion premium could, therefore, range from a few cents to US$1-US$2 per mmbtu. Thus, the depletion premium is usually determined at negotiations, and, while it is an economic yardstick, it becomes a financial cost in the final negotiated price. For this reason, the depletion premium cost was not included in the analyses, which provides both the minimum and maximum border prices, rather than an assumed fixed negotiated price (that is only known after negotiations).

6.7 The economic value of gas, whether domestic or imported, can be ranked third, if its delivered cost (at the point of consumption) does not exceed US$4.50 per mmbtu, a value representing the opportunity cost (netback value), assuming that 90% is used in a combined-cycle power plant and 10% is substituted for LPG in the industry where LPG is used for direct heat application.[2/] Given that the demand for gas in power (combined-cycle power generation) and industry (high-netback industrial use) far exceeds the projected available supply, the share of gas in total primary energy will thus be limited. This economic ranking of gas utilization has led to a substantial difference between the Bank's proposed supply options and those of EGAT and PTT. According to the Bank, the amount of gas allocated to industry would be less than that projected by PTT, because PTT assumes a large "under boiler" gas demand (by industry). However, the use of gas by industry for replacing fuel oil is not economic. As the result of this reallocation, more gas would be available to EGAT than is currently planned under its PDP. Further, the economic ranking of gas provides for its use (within the power sector) only in a combined-cycle power plant, which contrasts with EGAT's current practice where part of the gas is sometimes used as direct heat for raising steam in thermal power plants, substituting for coal or fuel oil; in this case, no advantage is taken of thermal efficiency gains inherent in the use of gas

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1/ In general, the whole issue of Thailand's hydro potential needs to be revisited because to date, only 28% of the country's hydropower has been developed (the balance is considered unexploitable for environmental and economic reasons). However, given the country's critical need for new energy sources, the Government should re-examine the hydro sites considered unexploitable with a view to determining whether, through improved financial packaging and better environmental mitigation actions, some could be developed.

2/ Such use has the highest economic value (para. 2.39). This is followed by the use of gas in industrial co-generation in which, similar to the combined-cycle power plant, gas achieves its second highest economic value.

in combined-cycle power plants and the economic value of gas is reduced significantly. Therefore, gas should only be used in the power sector for combined cycle power plants.

6.8 The concept of netback value provides that the highest prices that could be paid for gas are US$3.88, US$4.41 and US$4.75 per mmbtu in order for gas to compete with domestic lignite (with high efficiency FGD), low sulphur (0.5%) imported coal (with low efficiency FGD), and low sulphur (0.5%) fuel oil (without FGD), respectively (see para. 4.58 for the environmental costs). These are the breakeven costs above which the country should switch to lignite, coal and fuel oil, respectively. Because imported coal is assumed to be the long-term available energy source for Thailand, it is considered as the replacement fuel for gas. Hence, the value of gas in Thailand is assumed to be US$4.50 per mmbtu (which is the weighted ratio of gas netback value in imported coal-based power plant --US$4.41 per mmbtu-- and in industry, gas substituting for LPG at US$4.98 per mmbtu).

6.9 Domestic Gas. With regard to domestic gas, the economic cost of gas produced from the Unocal fields is estimated to be US$1.31 per mmbtu (which is somewhat cheaper than its original cost because the platforms already exist) and from the Bongkot field, US$1.67 per mmbtu.[3/] Since these two will produce the bulk of gas in Thailand in foreseeable future, the weighted average of their production costs together with gas transmission costs to Bangkok are used as the basis of the economic costs of domestic gas supply (estimated at US$2 per mmbtu).[4/] Since the maximum value of gas to the economy is US$4.50 per mmbtu, this gives a fairly wide margin (about US$2.50 per mmbtu) between the economic cost and value of domestic gas.[5/]

6.10 Imported Gas. Imported gas from Myanmar and Malaysia ranks fourth, provided that the cost of gas delivered to Bangkok would not exceed US$4.50 per mmbtu. In the case of Myanmar, this appears possible because its estimated economic cost delivered to Bangkok is US$2.26 per mmbtu (based on 300 mmcfd gas flow). This figures includes about US$0.57 per mmbtu to transmit the gas from the border to the Bangkok area. Therefore, Myanmar gas would give a maximum margin of US$2.24 per mmbtu. Although this margin appears to be high, the final price negotiated between Myanmar and Thailand (which would include some depletion premium), would result in a much narrower margin; thus, the Myanmar gas would be more expensive than the domestic supply. Given the above, Myanmar should receive a minimum of US$1.69 per mmbtu plus the depletion premium for its gas at the border, and Thailand should pay no more than US$3.93 per mmbtu. If the price were over US$3.93 per mmbtu at the Myanmar border, then Thailand should change to imported coal as the next best alternative fuel.

6.11 In the case of Malaysia, in addition to other issues discussed in para. 3.21, price is also a major concern. The economic cost of Malaysian gas delivered at the border is US$1.31 per mmbtu (based on a 300 mmcfd). However, because of the long transmission distance to Bangkok, the netback

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3/ Regarding development, production and transmission costs, these are not intended for investment decisions, but rather are to provide an order of magnitude.

4/ This economic cost, which excludes a depletion premium, should be distinguished from the financial cost which is the actual cost of gas sold by the producers to PTT and which averaged about US$2.10 per mmbtu at the well-head in 1992.

5/ It is based on this margin that the study recommends that the Government should support a more active exploration program to develop its hydrocarbon resources (para. 3.10).

value at the border is US$2-US$3 per mmbtu (depending on the pipeline routes), assuming that the entire 300 mmcfd is used in the Bangkok area. Considering that Malaysia's minimum expected price at the border is US$1.31 plus the depletion premium, a maximum margin of US$0.7-US$1.0 is left for negotiation, which is considerably lower than the maximum margin of US$2.24 for the Myanmar gas. Thus, its high cost (for consumption at Bangkok), combined with what appears to be simply an unwillingness to sell gas to Thailand, ranks this option low from a strategic point of view. However, if about 150 mmcfd of Malaysian gas is used in the Khanom power plant (which is now under construction at a location about 250 km. from the border), the drop-off at Khanom would boost its economic value.

6.12 While Government strategy should be to continue active discussions with both Myanmar and Malaysia, other more attainable targets should be pursued. For example, developing gas fields in the joint area between Malaysia and Thailand (JDA), should be a high priority, since it could be one of the least costly sources of supply, given the proximity of these fields (about 100 km.) to Thailand's gas infrastructure. For this reason, these reserves were included in the various options as a "most likely" scenario. More important, the option of importing LNG or coal, discussed below, should also be actively pursued.

6.13 ***Lignite***. Domestic lignite appears next in the economic ranking. This fuel will continue to play an important role in the power sector. It is expected that EGAT would continue to use lignite to meet the increased power demand, but would keep the share of lignite-generated power fairly constant at the current level, which is about 20% of power generation. Even under scenarios IIC and IIIC (coal scenarios for the second and third periods), it is expected the country would increase its coal imports rather than use lignite. However, as discussed in para. 3.32, the power expansion plans should be reassessed to incorporate the full cost of the lignite depletion premium along with the cost of pollution mitigation measures needed to comply with environmental standards. Therefore, in the study, the cost of power generation with lignite is based on its full economic cost when used in a power plant equipped with high-efficiency FGD. This cost is estimated at US¢5.06 per kwh. Accordingly, the study assumes that all the future lignite-fueled power plants would be equipped with high efficiency FGDs, that existing power plants would be retrofitted to include FGDs, and that the use of lignite in the industrial sector should be limited to cement plants where high efficiency FGDs are installed.

6.14 ***Low-sulphur coal***. Imported coal ranks low with respect to its economic value in power generation, but it assumes a much higher position in the Thai context. Thus, the proposed strategy calls for low sulphur imported coal to be the "mainstay" of Thailand's future energy supply, as long as its environmental problems are managed appropriately: It is readily available on international markets, relatively low cost and its prices are not expected to rise significantly (less than 1% per year) through the planning period. However, the environmental issues need to be resolved. Although the use of imported coal for power does not present many of the environmental problems associated with lignite-fired plants, authorities should comply with environmental regulations and select sites with care in order to avoid internal political conflicts and potential delays. These measures should be complemented by a public dissemination program, aimed at providing information about the low environmental impact of high quality coal in power generation. In the study, the use of low-sulphur imported coal (0.5%), which includes the installation of low efficiency FGD, brings the cost of power generation to about US¢5.60 per kwh, which ranks it after imported gas and domestic lignite. However, in the various options described above, where availability and high costs become constraining factors, the replacement fuel is assumed to be imported coal.

6.15 *LNG*. This fuel deserves special attention because of its high netback value in the combined cycle power plants. Based on current estimates of LNG prices in far eastern markets, the LNG option at US¢5.39 per KWh may rank higher than imported coal (without FGD). However, when used in combined-cycle power plants and substituted for higher value products in industry, its economic value, as with gas, is enhanced and the net benefit of using coal or LNG becomes identical or within the margin of error (see Table 6.2). Also, while at absolute levels the cost of LNG is considerably higher than coal, the environmental cost of the latter, its limited end-use applications and the difficulty of converting coal plants to either gas or oil-fired plants, provide added advantages to LNG. However, the comparison is based on current LNG prices and it also assumes that LNG will be available in the world market. To obtain a more accurate assessment of LNG availability and price, Thailand needs to start direct discussions with potential suppliers. For the purpose of these analyses, however, two separate scenarios have been developed (for LNG, Scenario "B," and for imported coal, Scenario "C").

6.16 *Oil*. The role of fuel oil in the power sector is declining and will continue to do so. The primary reason is that Thailand imports fuel oil (in contrast to many other countries that export it because of the excess amount produced in their refinery operations). Given the direction of future environmental considerations in Thailand, any future fuel oil imports would have to be of a low sulphur grade. But, low-sulphur fuel oil (which formed the basis for calculating the economic costs in this study, so as to internalize the environmental costs), is expensive and not readily available in the market. The second reason is connected to Thailand's policy with regard to diversification of fuels, which is to reduce its dependency on imported oil. Under the coal scenario, however, the share of oil would not decline because it has to compensate for part of the drop in gas consumption.

6.17 *Nuclear*. Nuclear power generation is not only a high capital-intensive option but its consideration requires assessing issues beyond the mere economics of the option. Nuclear power generation cannot be justified at this stage (para 3.73). Further, it is recommended that the country not to begin any actions related to a major nuclear program since the cost of inappropriately investing in this area would be too high. It fact, nuclear power would be justified only in the event that neither imported gas, coal nor LNG would be available, or if the price of these fuels would escalate dramatically above current levels --which seems a remote possibility. For these reasons, authorities should wait until at least some of the uncertainties associated with the gas supply and fuel prices are resolved, and then reassess the viability of a nuclear power program.

B. Supply Scenarios and Evaluation

Technical Factors

6.18 Based on the above ranking of the supply options, the following paragraphs describe several broad scenarios representing the most likely supply options expected in each period, based on their physical availability and total economic costs, which are considered to be "technical factors," in contrast to "policy factors" discussed in para. 6.30. The next section details the strategy proposed.

6.19 The planning time frame (1993-2010) has been divided into three periods: 1993-1998, 1998-2005, and 2005-2010. Within each period, three supply scenarios have been envisaged: Scenario "A," the "high" gas scenario, assumes an increase in domestic gas production, and a substantial volume

"A," the "high" gas scenario, assumes an increase in domestic gas production, and a substantial volume of gas imported from Myanmar and some from Malaysia. While gas is the predominant fuel under this scenario, the country would still need a significant amount of other fuels including oil, lignite and imported coal, depending on the period. Under Scenario "B," it is assumed that LNG would be the predominant fuel (by year 2000), but that other fuels, including domestic gas (and a modest quantity of imported gas) would also be used. Under Scenario "C," a "low" gas or coal scenario, the gas supply would be limited to the declining amounts produced domestically and modest imports from Myanmar, but there would be heavy reliance on imported coal.

6.20 During the first period, 1993-1998, the status quo would be altered only slightly (with respect to type and source of fuels), because any new initiatives beyond the projects already underway could not be completed. Two gas transmission projects are underway: The Bongkot Gas Transmission Project (financed by the Bank) which will be finished by the end of 1993, will initially increase the gas supply by 150 mmcfd, and, based on current reserve levels will reach 300 mmcfd during the plateau years. The Second Gas Transmission Project, scheduled to be completed by mid-1997, will initially add 200-300 mmcfd, and, depending on the availability of gas, could eventually reach 500-800 mmcfd. These projects will provide ample pipeline capacity to transport the entire volume of Thailand's identified gas reserves, as well as over 50% of the country's "probable" reserves. In addition, two refineries under construction, joint-ventures with Shell and Caltex, each with a nominal capacity of 125,000 bpd, are scheduled to be completed by late 1997.

6.21 Should major oil or gas fields be discovered, they could not be developed in less than three or four years; therefore, they would not provide new supplies before 1998. Similarly, in the event that negotiations with Myanmar and Malaysia (regarding gas imports to Thailand), are concluded shortly, the actual delivery would still not occur before 1998. The same is true with LNG, since any LNG import project would not be completed before 1998. Thus, no new energy source is envisaged within this period. Instead, the increase in domestic gas supply and refining capacity, the marginal increase in the production of condensate and in the import of coal, and substantial increase in the import of oil from the international market, as well as the increased production of domestic lignite, would meet the country's additional energy needs. With respect to consumption, the volume of domestic gas used in industry and power will rise, that of woodfuels, both in industry and the residential sectors, will drop, and that of lignite and coal will increase marginally.

6.22 However, during the first period, the Government must make crucial decisions about the types and sources of fuel for the second and third periods: Within the next year or two, work should be initiated for importing LNG (and coal); and, negotiations with the governments of Laos, Myanmar and Malaysia for importing hydroelectricity and gas need to be concluded in order to meet Thailand's energy needs during second and third periods.

6.23 The second period, 1998-2005, will bring major changes in the energy supply: Piped gas could be imported from Myanmar and Malaysia, or LNG and coal could come from international markets. These changes will occur because by early 1998, Thailand's energy demand will exceed the presently identified supply options, and it will therefore need to import coal and/or gas (piped or LNG), or increase its oil imports.

6.24 Given the recent setback in negotiations with Malaysia and the renewed signals from Myanmar on its willingness to sell gas to Thailand, the likelihood of gas imports from Myanmar has become greater. Besides, since the economic cost of gas from Myanmar is less than that of Malaysian

gas, it provides a wider margin and hence facilitates negotiations. Therefore, it was assumed that by the end of 1994, a gas purchase-sales agreement would be signed between Thailand and Myanmar, construction for the project would begin in mid-1995, and an initial volume of 300 mmcfd of gas (increasing eventually to 500 mmcfd) would be transported by early 1998. As a possible option (only under high gas scenario), it was also assumed that the unresolved issues between Malaysia and Thailand would be cleared, particularly after Malaysia finishes constructing its domestic gas network --including the segment to the Thai border-- and thus would have an incentive to sell gas to Thailand for consumption in the Songkhla/Khanom region. Accordingly, it was assumed that gas will be imported from Malaysia beginning in early 2001, at a rate of 150 mmcfd.

6.25 A situation under which Thailand would not be able to import significant volumes of gas from Myanmar or any gas from Malaysia has also been examined. The impasse with Malaysia could easily continue for years because the two countries have different gas utilization needs and disagree on the price and quality of the gas. As discussed in para. 3.21, until now, Malaysia has argued that its border price should be comparable to that of gas sold to Singapore --namely, a border price equivalent to fuel oil plus 7%. While this may be economic for Singapore, given its proximity to Malaysia, it is not economic for Thailand, because the latter would incur substantial costs transporting the gas over 800 kilometers to the main consuming center (in the Bangkok area). In fact, the combination of issues, and particularly the pricing, makes the import of large quantities of Malaysian gas rather unlikely. With Myanmar, although the situation has improved because of the recent agreement signed between PTTEP and the Government of Myanmar, a stalemate could still develop because of present political difficulties in that country which would make long-term commercial contracts unsustainable. The situation may have become further complicated by a change in EGAT's plan to relocate the site of the power plant from the vicinity of the Thai-Myanmar border to a location near Bangkok: The additional distance translates into higher transportation costs for gas delivered to Bangkok. Nonetheless, the Myanmar option at 300 mmcfd is considered quite likely.

6.26 In the event the above difficulties develop, Thailand's next best alternatives are either to import liquified natural gas (LNG) or coal.[6/] However, the choice between coal and LNG will depend on various factors including prevailing prices, environmental considerations, availability and reliability of supply, end-use applications, and the Government's strategic policy on diversification of fuel sources. If Thailand decides to import LNG, the scenario for this option would be similar to the piped gas import option with respect to quantity and timing: Namely, it is assumed that Thailand would search for a long-term supplier of LNG in Asian or Persian Gulf markets soon after it concludes that negotiations with Myanmar and/or Malaysia are fruitless. The first LNG train (4 million ton per year (mt/y) capacity) would supply 485 mmcfd of LNG-based gas by early 2000, followed by the second train, which would supply an additional 485 mmcfd by the year 2005. Therefore, the decision to construct LNG import facilities would also have to be made during the first period (by the end of 1994).

6.27 To summarize the second period, the study assumes that by early 1998, Thailand would import about 300 mmcfd of gas from Myanmar and that by 2001, an additional 150 mmcfd of gas would be imported from Malaysia under the "high" gas scenario (Scenario IIA). Under this scenario, gas would be the predominant fuel, although others would also be used. Alternatively, Thailand will

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6/ Even if the country succeeds in importing gas from its neighbors, the projected quantities are not sufficient to meet the country's demand by 2010.

import about 485 mmcfd of LNG-based gas from international markets by 2000 (Scenario IIB). In this scenario (IIB), LNG would be the predominant fuel. Under scenario IIC, Thailand would not import significant volumes of piped gas, nor any LNG, but substantial amounts of coal; and, it would also increase its import of oil and consumption of lignite. Due to the long lead-time needed to implement either LNG or coal-receiving terminal projects, the choice must be made by mid-1994, as soon as the uncertainty related to the availability of imported gas is resolved.

6.28 Predicting the energy scene during the third period, 2005-2010, is more complicated. If, during the second period, Thailand imports gas from Myanmar and Malaysia (Scenario IIA), it is possible that it would increase the amounts during the third period, to 500 mmcfd from Myanmar (Scenario IIIA). This is not unrealistic (if the initial import scenario materializes), because Myanmar's gas reserves are sufficient to accommodate an increase, subject to agreement on the terms. Since the pipeline would already be constructed, the additional expenditure required for increasing the throughput is marginal; therefore, both sides have incentives to conclude a new bilateral agreement based on an increased quantity of gas. If, on the other hand, scenario IIB occurs during the second period (where Thailand imports 485 mmcfd of LNG-based gas), the amount would increase during the third period to about 970 mmcfd (Scenario IIIB). Under both scenarios (IIIA and IIIB), shortfalls in the energy supply would be met by substantially increased imports of coal and marginal increases in the import of oil and the production of domestic lignite.

6.29 However, if, during the second period, neither piped gas nor LNG materialize, and Thailand imports large quantities of coal and an increased amount of oil (i.e., under Scenario IIC), then the nuclear option may be pursued during the third period (Scenario IIIC), because the Government would attempt to reduce its reliance on imported oil and diversify the source of the country's fuels. The issues and options regarding nuclear energy are discussed in Chapter III, which concludes that: (a) nuclear-based power generation is not economic and (b) if the Government decides to move in this direction, work on a nuclear program should begin now, so as to have this power available by 2006. However, because that option is uneconomic, the study does not promote it. Table 6.1 presents a summary of these scenarios.

TABLE 6.1: THAILAND - Summary of Fuel Supply Scenarios

Time-frame	Energy Scenario	Fuels Included
I: 1993-1998	Status quo	Imported oil; domestic gas, lignite and small amount of hydro; small quantities of imported coal and hydro.
II: 1998-2005		
IIA	Imported gas	Imported oil; significant quantities of domestic and imported gas; domestic lignite and small quantities of hydro; small quantities of imported coal and hydro.
IIB	Imported LNG	Imported oil; lesser amount of domestic and imported gas; significant quantities of LNG; lesser domestic lignite and small quantities of hydro; small quantities of imported coal and hydro.
IIC	Imported coal	Imported oil; lesser amount of domestic and imported gas; lesser domestic lignite and small quantities of hydro; significant quantities of imported coal and small amount of imported hydro.
III: 2005-2010		
IIIA	Imported gas	Imported oil; declining quantities of domestic and significant quantities of imported gas; more domestic lignite and small amount of domestic hydro; moderate amount of imported coal and small amount of imported hydro.
IIIB	Imported LNG	Imported oil; declining quantities of domestic gas and lesser amount of imported gas; significant quantities of imported LNG; lesser domestic lignite and small amount of domestic hydro; moderate amount of imported coal and small quantities of imported hydro.
IIIC	Imported coal or nuclear	Imported oil; very little domestic and lesser amount of imported gas; significant quantities of imported coal and small quantities of imported hydro; lesser domestic lignite and small amount of hydro.

Source: Bank mission.

Policy Factors

6.30 The choice of fuel supply will depend not only on the physical availability and economic viability of a particular supply option, but also on the prevailing policy framework which supports the structure of the energy sector in the economy. As discussed in para. 6.19, the study's time frame was divided into three periods based on the likely scenarios resulting from technical factors influencing the supply options (such as the availability and the economic costs of the supply). The study subsequently re-examined the above scenarios with a view to assess the impact of the prevailing policy factors in each period (such as organization, ownership, regulation, and financing of the sector) on the supply options. While it is possible to project with a reasonable degree of accuracy the physical and economic feasibility of the different supply options, it is more difficult to predict the future policy actions. However, the study assumes that Thailand would continue its macroeconomic stabilization, fiscal and monetary discipline, and would provide a predictable climate for foreign and domestic investors. This

assumption also implies that future changes in the organization, ownership, regulation and financing of the sector would follow a rational course of development, consistent with the objective of enhancing sector efficiency. Based on these assumptions, the following policy-based scenarios are envisaged to develop in each period.

6.31 During the first period, 1993-1998, the policy factors (as with the technical factors), are not expected to affect the country's present energy supply options: Even if a policy decision on restructuring the sector, such as changing the ownership of the energy entities or establishing an independent regulatory body, was initiated today, its implementation would not begin before the end of this period. This is in part due to the energy sector's legal framework which requires major modifications (and subsequent ratification) in the acts which created the entities, before any major restructuring of the sector becomes meaningful. It is also due to the fact that the investment decisions and sources of financing --which are often the impetus to policy changes-- for major projects scheduled to be implemented in this period, have already been taken and secured.

6.32 Although major restructuring will not occur during the first period, the sector's investment needs for the second period would require that fundamental decisions, with regard to sector reform, be made during the first period. This is because new sources of capital must be found to finance the massive infrastructure needed to meet the country's growing energy demand. In addition, the Government wants to enhance the entities' efficiency, even further, and the entities want to reduce the political form of governance so they can maximize their profits. Thus, during the first period, the Government and the entities will both focus on capturing the economic values inherent in the energy sector and on preparing a blue print for the country's future supply options, the basis of which would be profit maximization. However, during this period, because the main actors will remain unchanged, so too will the motivation: Entities will attempt to meet certain performance criteria, such as those set by Ministry of Finance for PTT, rather than a set of commercial objectives; the environmental policy will continue to be dictated by mitigating risks through physical and technological means (such as installing scrubbers and high efficiency FGDs) rather than through financial and policy measures (taxes and incentives); and the regulatory mode would continue as before, with the Government providing ad hoc regulatory directives to reverse the adverse consequences of market shortcomings rather than providing incentive-type regulations.

6.33 As a result of the incremental changes that will occur during the first period, it is expected that the state energy enterprises will be corporatized by the beginning of the second period (1998-2005). It is also expected that the regulatory framework would be completely independent. The reason for emergence of a corporatized structure is that the energy entities cannot raise the financial resources needed and further commercialization under the current legal regime will not yield substantially greater benefits (either to the Government or the entities). Also, the full privatization of the entities by the second period is not feasible or preferable, either, because (a) the Government could not sell them at an optimum price since their operations could not have been tested on a fully-commercial basis; (b) some of the previous investments have not yet borne fruit and (c) given the absence of an institutional and legal framework to support the principle of privatization at the national level, the privatization of the energy entities alone would not be a panacea to maximize efficiency.[7/] However, a fully independent regulatory body would be needed during the second period to assure the private sector that its

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7/ However, there are possibilities for partial privatization of some of the energy entities or full privatization of some of their subsidiaries and joint venture companies.

investments would be governed by a clear set of rules and means of enforcement; the rules based on promoting fairness in investment, prices and entry and exit to the sector. These are briefly discussed below.

6.34 During the first period, the energy entities, which carry out their day-to-day operations with a reasonable degree of efficiency and commercially-based approach, will try to maximize efficiency within the existing mode of operations, as well as take additional steps to adopt a more commercial strategy. These would include focusing more intensely on a set of profit targets, phasing out non-commercial practices and projects, adopting international standards on accounting and budgetary procedures using independent external auditors instead of the Government's general auditors, providing salaries comparable with commercial sector, and exercising autonomy in procurement and recruitment. In terms of organizational changes, some entities, such as PTT, would continue their reorganization, which will result in several business units that operate on a profit and loss basis.

6.35 Despite their usefulness, these measures will not be sufficient to ensure a profit-maximizing operation: The Government still retains ownership and appoints the board, which in most cases is composed of members of Government. As such, the energy entities still must comply with Government requests which sometime include non-commercial activities for which they are not directly compensated. Lacking a set of proper corporate laws, an independent regulatory body and balance sheet which reflect full capital structure, any independence gained under commercialization drive would be eroded after a while.

6.36 Because the key issue is raising sufficient capital (as opposed to gaining efficiency --since they are already reasonably efficient), the status quo cannot be maintained. Thus, they must move towards corporatization or full privatization.

6.37 However, the complete privatization of the two major energy entities (EGAT and PTT) may not be the preferred solution for the second period: If improving the operational efficiency of the two entities is the objective of privatization, as discussed in para. 5.10, both entities already operate efficiently and have substantial market discipline. Any further improvement in the entities' efficiency may require a fundamental change in institutional structure at the national level, in order to deal with legal and market aspects of privatization across economy; and, this change is not likely to occur on such a short time span. If the objective is to raise government revenue, it is unlikely that the second period would represent the optimum time for selling the entities, because neither PTT or EGAT would have operated on a full profit-loss basis; and, moreover, some of their major investments, particularly in the case of PTT, would not be operational before 2000-2004. Finally, if the objective of privatization is to increase the flow of private capital (that is, increasing it beyond the level obtained through corporatization), it is unlikely the private sector would undertake strategic projects alone, such as importing LNG, coal, gas and hydro, because of the large capital outlays and the risk involved. Therefore, it is not envisaged that the "total" privatization of either of the two entities would materialize during the second period.

6.38 Thus, the most likely course is that the entities will be fully corporatized during the second period. (Corporatization is often a first step in the process of privatization). Besides, corporatization seems to be consistent with the realities in Thailand's energy sector, in that such a structure would benefit both the Government and the energy entities, at least for the next decade or so: It will allow the latter to act as private sector organizations and pursue their profit maximization goals, but the Government could hold all or part of the shares provided that it recognizes that the entities need to

operate on a fully commercial basis; this would include a completely autonomous board that would decide what constitutes commercial activities. The Government role here would be similar to the private company vis-a-vis its subsidiary.

6.39 The picture after 2005 (the third period) becomes somewhat fuzzy with respect to the sector's organization and ownership structure because the matrix of supply options will include numerous possibilities resulting from interactions of a variety of technical and policy factors discussed above. In addition, other supply options, such as nuclear, may emerge, because of the Government's strategic decisions with respect to security of energy supply, the environment and the international energy market. It is expected that during this period, the sector will either maintain its corporate status or move toward partial privatization of the entire enterprise or full privatization of some of the units and subsidiaries. This will occur after the enterprises have gained substantial experience in profit maximization and/or they are seeking more private capital.

6.40 With regard to the regulatory framework, it is expected that as the need for private sector participation increases and the corporatization process deepens, the need for an independent and effective regulatory framework will also increase (see para. 5.20).

Cost-Benefit Analysis

6.41 A cost-benefit analysis of various supply options and scenarios were carried out. The resulting matrix, in terms of the net benefits of the various options, is presented in Table 6.2.

6.42 As shown in Table 6.2, the total quantity of energy required under either the LNG or imported coal options, is slightly less than that required under the gas options: Under these two scenarios, the cost of power generation would be high and would affect the demand for electricity. In turn, reduced electricity demand would lower the level of primary energy required. In terms of costs, the LNG option is the highest in the second and third periods (the first does not include LNG since it only begins to be imported in 2000), and the coal option is the lowest in the second and third periods but only slightly higher than the cost of the gas option in the first. The minimum cost of coal option during the second and third periods are higher than the minimum costs of gas option because of increased consumption of petroleum under the coal scenario. However, the above figures reflect only the economic cost of supplying a composite unit of energy to Thailand; when the economic values of the same composite unit are evaluated, the results are substantially different because these values (netback) vary according to the applications and sectors. As a result, the evaluation of the options' net benefits (the difference between the economic costs and values) in 1998 indicates that the gas option has a higher net benefit than the coal option. In 2005, the benefits of gas are even higher than both of coal and LNG (because domestic gas production reaches a plateau), while the net benefits of LNG is higher than coal. In 2010, the net benefits for gas drop (because domestic gas production begins to decline), while those of LNG and coal are almost identical.

TABLE 6.2: THAILAND - Quantities and unit Cost of Projected Primary Energy Requirements
(Ktoe and US$)

Fuel	1993	1998			2005			2010		
		A	B a/	C	A	B	C	A	B	C
Oil	23,694	32,028	32,537	32,537	48,354	47,594	48,796	63,278	61,587	63,717
Gas	7,376	14,691	12,923	12,923	24,178	22,402	13,826	18,305	16,237	7,661
Coal	380	533	828	828	800	1,280	8,895	15,066	15,844	22,733
Lignite	4,536	6,238	5,875	5,875	10,070	9,331	9,331	13,516	12,551	12,551
Hydro	378	527	480	480	601	538	538	720	643	643
Total Comm.	36,364	54,017	52,644	52,644	84,003	81,145	81,387	110,885	106,862	107,305
Non-comm.	7,470	8,058	8,384	8,384	8,588	9,308	9,308	8,808	9,852	9,852
Total (ktoe)	43,834	62,075	61,028	61,028	92,591	90,453	90,695	119,693	116,714	117,157
Composite Cost (US$/mmbtu)	-	2.75 to 2.89	2.79 to 2.94	2.79 to 2.94	2.77 to 3.00	2.97 to 3.15	2.82 to 2.92	2.89 to 3.09	3.13 to 3.29	2.93 to 3.04
Composite value b/ (US$/mmbtu)	-	3.45	3.42	3.42	3.60	3.58	3.28	3.39	3.36	3.13
Net Benefits (US$/mmbtu)	-	0.56 to 0.70	0.48 to 0.63	0.48 to 0.63	0.59 to 0.82	0.42 to 0.60	0.36 to 0.47	0.30 to 0.50	0.07 to 0.23	0.09 to 0.20

Source: Bank mission.
a/ There is no LNG in this period: Hence, B = C.
b/ Refers to enhanced value of gas, due to thermal efficiency, when used in combined-cycle power plants.
A = Gas dominating.
B = LNG dominating.
C = Imported coal dominating.

6.43 The analysis provides two conclusions. First, substantial benefits are associated with the use of gas if it is supplied at a cost of not more than US$4.50 per mmbtu --either through an increase in domestic production or the import of gas from Myanmar and/or Malaysia. Second, if increased domestic gas production or imports do not materialize, then LNG and/or imported low-sulphur coal are the next best alternative fuels. The choice between LNG and coal requires a careful evaluation of the issues related to these two fuels, including a realistic projection of LNG future prices and availability. The preliminary analysis (in the study) indicates that the difference between the net benefits of the two while favors LNG during the second period, is insignificant and well within the margin of error for the third period.

6.44 With respect to the power sector, after DSM and hydroelectricity, both of which are in limited quantities, the least-cost solution for meeting Thailand's rapidly growing power demand is through extensive use of natural gas in combined-cycle plants. And, based on the Bank assessment of domestic natural gas resources, the potential gas supply available to EGAT is likely to be larger than previously thought; thus, gas-fueled power plants could be increased by 3,000 MW, compared to EGAT's power development plan for the 1997-2001 period. In the event imported natural gas is available from Myanmar and Malaysia, total gas-based power capacity would increase even further, particularly if the industrial gas demand is reduced to the level projected by the Bank.

6.45 A power expansion program based on the extensive use of natural gas offers considerable economic advantages as well as important environmental benefits. Gas would also reduce SO_2 emissions by 220,000 tons per year (by 2005), a reduction that would cost US$350 million if achieved through emission mitigating measures (FGD) in lignite-fired plants. Conversely, if additional gas supplies from neighboring countries are not secured, the total cost of the power supply would increase by 7% over the planning horizon (gas would be replaced mainly by imported coal and fuel oil) which would translate into an additional costs.

6.46 However, even if larger domestic gas reserves are confirmed and/or imported gas is secured, the projected natural gas supply would still not be sufficient to meet Thailand's future power generating needs. Therefore, natural gas has to be complemented by other energy resources, such as imported coal.

C. Investment Requirements

6.47 ***Non-power capital investment.*** The capital investment required to meet the various options falls into two broad categories: the non-power and power sector expenditures. Non-power capital expenditures include the costs of gas transmission, LNG regasification costs and coal import facilities (see Table 6.3). They do not include the costs of hydrocarbon field development and production, gas purchase at the border, or the CIF price of LNG nor do they include those associated with lignite transfer or oil purchases.

TABLE 6.3: THAILAND - Non-Power Investment Requirements
(US$ million)

Components	1993 - 1998	1998 - 2005		
		A	B	C
Bongkot Gas Transmission Project	370	100 a/		
2nd Gas Pipeline Transmission Project	700	100 a/		
Myanmar Gas Import (Thailand's share)	400	200+150 a/		
Malaysia Gas Import (Thailand's share)	-	-		
1st LNG Regasification Plant	-	-	515+365 b/	
2nd LNG Regasification Plant	-	-	270+175 b/	
Imported Coal Port	-	-	-	500 c/
TOTAL	1,470	550	1,325	500

Source: Bank mission.
A - Gas dominating; B - LNG dominating; C - Coal dominating.
a/ High gas expansion.
b/ Ranong - Ratburi Pipeline or Rayong-Bangkok pipeline, depending on LNG terminal location.
c/ Rough estimate, could also be used for 3rd LNG regasification.

6.48 ***Power sector capital investment requirements.*** The expansion of Thailand's power system, designed to fulfill its rapid growth expectations, has required large capital injections: Power

sector public investments accounted for 20% of total public investment and 40% of state corporation investments from 1983-1991 and have had an important macroeconomic impact. While they absorb a considerable amount of savings, due to their capital-intensive nature and the high component of imported capital goods, they have led to heavy external borrowing. As a result, the power sector debt --both outstanding and disbursed-- exceeded US$4 billion by the early 1990s, accounted for more than 25% of Thailand's public and publicly guaranteed debt, and placed an increased pressure on the balance payments (Annex 14).

6.49 Future capital requirements for power generation and transmission, for the 1993-2006 period, are estimated from US$36 billion-US$42 billion, depending on whether additional natural gas would be available. EGAT's PDP capital requirements, which are consistent with the high value of the above given range, are presented in Table 6.4. The values indicate that the impact of power sector investments on the economy will continue to grow as these investments are expected to increase at an annual rate of over 10%, while GDP growth is expected to be between 7%-8%. This trend casts doubts on the sustainability of public power investment; thus, power investment should be placed in a macroeconomic context where supply and demand constraints should be adequately considered to ensure a viable program. Given the rapid expansion of Thailand's economy, the key issue is how the power sector can contribute to sustained economic growth in a manner consistent with an equilibrium in the balance of payments. In this sense, mobilizing new financial resources through increased participation of the private sector becomes highly attractive (paras. 6.30-6.40).

TABLE 6.4: THAILAND - Power Sector Investment Requirements
(Generation and Transmission)

Year	million Baht (current)	million US$ (constant 1992)
1992	25,880	995
1993	34,686	1,270
1994	58,162	2,029
1995	58,349	1,939
1996	80,923	2,562
1997	92,636	2,793
1998	108,699	3,119
1999	111,659	3,053
2000	108,028	2,813
2001	149,977	3,715
TOTAL	828,999	24,288

Source: EGAT"s PDP 92-01, including projects of the Sixth, Seventh and Eighth Plans.

D. Proposed Strategy and Recommendations

6.50 The economic cost of the supply options identified above would be about US$7 billion per year by 1998, and the capital investment required to build the needed infrastructure to supply this

energy to the economy is estimated at US$45 billion over the next 15 years. The proposed strategy calls for the Government to take actions in four key areas: (a) initiating and or concluding a variety of strategic measures which are needed to bring the optimum supply option to fruition; (b) mobilizing the finances to implement the recommended option; (c) implementing other measures necessary to ensure the sustainability of the selected option and (d) establishing a framework for environmental policy and standards in the country.

6.51 ***Strategic Measures.*** Regarding the first area, the proposed strategy calls for the Government to take the following measures directly associated with fuel supply options:

(a) Closely monitor the on-going DSM program of the power sector in order to assess its long-term potential, and if its implementation is successful, increase its scope;

(b) Initiate and conclude with Laos, as soon as feasible, negotiations to import hydroelectricity, and participate, as a joint venture, in the financing of the project so as to mobilize funding for Laos and assure that country of Thailand's long-term commitment to the project;

(c) Accelerate the exploration of the country's hydrocarbon basins, and review the existing fiscal regime and contractual terms with a view to relax them and provide incentives for increased private sector participation in exploration and production; in particular, accelerate the development of JDA gas fields;

(d) Intensify negotiations with Myanmar and Malaysia regarding the import of gas, and conclude, by end-1994, whether gas imported from either country or both is a viable option;

(e) Enter into active discussions with the potential supplier of LNG and conduct a more detailed evaluation on the economic, institutional and environmental feasibility (including sites selection) of importing LNG with a view to determine, by the end of 1994, if this option can materialize;

(f) Conduct the preparatory work for importing coal, which would include selecting a site for handling coal, conducting a pre-feasibility study for the port facilities, and completing it by mid-1994; given that the imported low sulphur coal is the mainstay of the country's fuel supply structure, and that during the third period, a substantial amount will be needed to meet the country's energy requirements (regardless of which supply option is chosen;

(g) Re-examine the country's hydro sites to determine whether through improved financial packaging and better environmental mitigation plans, some of these sites could be developed given the country's critical needs for new sources of energy.

6.52 ***Mobilizing Finances.*** With regard to the second area, as discussed in paras. 6.30-6.40, the proposed investment is huge, will undoubtedly have a major impact on the Government's investment and funding policy and will require far greater participation by the private sector. While the private sector is currently very active in Thailand's energy sector, including in all upstream operations in oil and gas, as well as in a major part of refinery, petrochemical, and lube oil plants and in the distribution of oil products, it would not be able to undertake investment of such magnitude without Government

support, either directly or through mediation for private and international funding. Nonetheless, the private sector role needs to be increased beyond the present boundary because it is doubtful if this size investment and expenditure can be sustained by the public sector alone, without constraining the country's economic growth. The Bank-proposed strategy supports the implementation of a least-cost program without addressing the appropriate proportion between public and private investment. However, as discussed in paras. 6.30-6.40, this issue need to be addressed soon, and comprehensively, since the mix of public and private sector in Thailand's energy sector would have a significant impact on the country's fuel supply options.

6.53 ***Other Measures.*** The third area involves other measures the Government must take, not directly related to supply options, but necessary to ensure the sustainability of the selected option. With regard to pricing policy, the future price of gas to be supplied by PTT to EGAT should be based on a long-term formula in line with international standards; that is, through separate agreements for firm and interruptible gas supply according to the scope of the ongoing study, which should be finalized as soon as possible.

6.54 In general, the level and structure of electricity tariffs are adequate. However, the tariff system has some distortions, the most important of which is the lack of an adequate structure for distribution companies, which pay no capacity charges. In order to ensure the success of current peak-shaving efforts (which would reduce future investments), a cost-based structure should be developed for the distribution companies.

6.55 Also, the transfer price used by EGAT for domestic lignite must be reviewed with the goal of evaluating a more realistic depletion premium. In this regard, special care should be taken to incorporate a sufficiently long time frame into the planning process in order to capture the long-term effects of the depletion premium.

6.56 With regard to institutions, NEPO should be strengthened. Institutional building efforts should include increasing the number of its staff and training staff in various fields such as energy pricing, international oil and gas markets, specific planning skills to design and monitor contracts with private power suppliers: also, the organization should implement a management information system.

6.57 A suitable legal and regulatory framework for the energy sector should be designed and applied. It should be the subject of a careful study that would define the roles to be played by the Government, regulatory entity or entities, energy sector enterprises and interest groups. Key issues would be the type of regulatory entities that could most effectively create an enabling environment for private sector participation and privatization of public energy entities. Further, issues such as whether there should be a single regulatory body or different regulators for each sub-sector must be carefully assessed.

6.58 The Department of Mineral Resources should be strengthened so as to increase its capacity to assess hydrocarbon reserves, conduct preliminary explorations and analyze the country's fiscal regime in the context of gas-utilization economics.

6.59 Several actions are recommended in order to strengthen PTT's and EGAT's commercial activities and prepare the two entities for future privatization:

(a) The Government should amend the acts creating PTT and EGAT, providing them with the latitude to expand their business activities and strategic planning, which would include diversifying their financial portfolios;

(b) The present onlending arrangement between the Government and the entities --through which the Government does not charge an onlending fee-- needs to be re-examined so that PTT and EGAT could operate on a fully commercial basis;

(c) The implied monopoly position that PTT and EGAT enjoy, such as the limitation applied to cogeneration and restrictions on lignite production, should be reviewed in order to allow greater private participation.

(d) The software and data base currently used by EGAT in its planning process should be examined along the lines presented in Chapter III.

6.60 ***Environmental Measures.*** With regard to fourth area, the Government must finalize environmental policies and standards on which investment decisions can be calculated and the least-cost schemes of energy supply could clearly be determined. This study recommends the following measures:

(a) Incorporating into the design of all future lignite-fired power plants a high efficiency FGD and assessing each of the existing plants to establish an economic way of retrofitting them with a combination of low and high- efficiency FGD;

(b) Using low-sulphur fuel oil and imported coal in both the power sector and industry, and incorporating their costs into the planning process of future power and industrial plants.

ANNEXES

THAILAND
FUEL OPTION STUDY

Table A1.1: GDP and Energy Demand Projection

YEAR	OVERALL		INDUSTRY				TRANSPORT				AGRICULTURE				RESIDENTIAL/COMMERCIAL			
	FINAL ENERGY (KTOE)	GDP-72 PRICES (MMBAHT)	ENERGY (KTOE)	%	INDUSTRY GDP (MMBAHT)	%	ENERGY (KTOE)	%	TRANSP. GDP (MMBAHT)	%	ENERGY (KTOE)	%	AGRIC. GDP (MMBAHT)	%	ENERGY (KTOE)	%	SERVICE GDP (MMBAHT)	%
1993	34692	801261	11089	33	283905	35	13786	39	53273	7	2003	6	99647	12	7714	22	364536	45
1994	36855	863759	11844	32	309458	36	14970	41	57270	7	2088	6	102831	12	8053	22	392973	45
1995	39490	931133	12651	32	337310	36	16256	41	61566	7	2176	6	106224	11	8408	21	423628	45
1996	42210	1003761	13512	32	367666	37	17652	42	66184	7	2268	5	109729	11	8778	21	456675	45
1997	45129	1082054	14432	32	400759	37	19169	42	71149	7	2364	5	113349	10	9164	20	492299	45
1998	48281	1166455	15415	32	436829	37	20815	43	76487	7	2464	5	117089	10	9567	20	530703	45
1999	50688	1244607	16303	32	473959	38	22180	44	81307	7	2552	5	120835	10	9932	19	566261	45
2000	53833	1327996	17242	32	514246	39	23636	44	86430	7	2644	5	124701	9	10312	19	604201	45
2001	56886	1416871	18235	32	557957	39	25186	44	91877	6	2739	5	128691	9	10706	19	644683	45
2002	60075	1511909	19285	32	605383	40	26838	45	97666	6	2837	5	132809	9	11114	19	687878	45
2003	63473	1613206	20398	32	656641	41	28599	45	103821	6	2939	5	137058	8	11539	18	733966	45
2004	67070	1721291	21571	32	712672	41	30475	45	110363	6	3045	5	141443	8	11979	18	783143	45
2005	70878	1836618	22813	32	773249	42	32474	46	117318	6	3154	4	145968	8	12437	18	835615	45
2006	74372	1956998	23853	32	835112	43	34390	46	124476	6	3241	4	150618	8	12898	17	889893	45
2007	78045	2083138	24941	32	901023	43	36398	47	132071	6	3330	4	155209	7	13377	17	947697	45
2008	81907	2218542	26078	32	974080	44	38535	47	140130	6	3421	4	160046	7	13873	17	1009256	45
2009	85986	2362747	27267	32	1052009	45	40798	47	148680	6	3515	4	165034	7	14387	17	1074813	45
2010	90234	2516326	28510	32	1136173	45	43191	48	157751	6	3612	4	170178	7	14921	17	1144629	45
COMPOUND GROWTH RATE																		
1993-1998	6.89%	7.80%	6.81%		9.00%		8.59%		7.50%		4.23%		3.30%		4.40%		7.90%	
1998-2005	5.64%	6.70%	5.76%		8.50%		6.56%		6.30%		3.59%		3.20%		3.82%		6.70%	
2005-2010	4.95%	6.50%	4.56%		8.00%		5.87%		6.10%		2.75%		3.12%		3.71%		6.50%	
AVERAGE ELASTICITY																		
1993-1998	0.88		0.76				1.15				1.28				0.58			
1998-2005	0.84		0.68				1.04				1.12				0.57			
2005-2010	0.76		0.57				0.96				0.88				0.57			

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

Table A2.1: Projection of International Prices of Fuels; (C.I.F.) Bangkok

		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
CRUDE (1)	$/BBL	16.60	16.40	16.60	17.14	17.70	18.28	18.88	19.50	19.31	19.11	18.92	18.73	18.50	18.69	18.89	19.09	19.29	19.49
	$/MBTU	3.03	2.99	3.03	3.13	3.23	3.34	3.45	3.56	3.53	3.49	3.46	3.42	3.38	3.41	3.45	3.49	3.52	3.56
LPG (2)	$/BBL	20.00	19.76	20.00	20.65	21.33	22.03	22.75	23.49	23.26	23.03	22.80	22.57	22.29	22.52	22.76	23.00	23.24	23.48
	$/MBTU	4.98	4.92	4.98	5.15	5.32	5.49	5.67	5.86	5.80	5.74	5.68	5.62	5.56	5.61	5.67	5.73	5.79	5.85
GASOLINE (3)	$/BBL	25.07	24.76	25.07	25.89	26.73	27.61	28.51	29.45	29.15	28.86	28.57	28.28	27.94	28.23	28.52	28.82	29.13	29.43
	$/MBTU	5.28	5.22	5.28	5.46	5.63	5.82	6.01	6.21	6.14	6.08	6.02	5.96	5.89	5.95	6.01	6.08	6.14	6.20
KERO/JET (4)	$/BBL	24.90	24.60	24.90	25.71	26.56	27.42	28.32	29.25	28.96	28.67	28.38	28.10	27.75	28.04	28.34	28.63	28.93	29.24
	$/MBTU	4.78	4.73	4.78	4.94	5.10	5.27	5.44	5.62	5.56	5.51	5.45	5.40	5.33	5.39	5.44	5.50	5.56	5.62
DIESEL (5)	$/BBL	25.23	24.93	25.23	26.06	26.91	27.79	28.70	29.64	29.34	29.05	28.76	28.47	28.12	28.42	28.71	29.02	29.32	29.63
	$/MBTU	4.60	4.54	4.60	4.75	4.90	5.06	5.23	5.40	5.35	5.29	5.24	5.19	5.12	5.18	5.23	5.29	5.34	5.40
FUEL OIL (6)	$/BBL	13.78	13.61	13.78	14.23	14.69	15.17	15.67	16.19	16.02	15.86	15.70	15.55	15.35	15.52	15.68	15.84	16.01	16.18
	$/MBTU	2.30	2.27	2.30	2.37	2.45	2.53	2.61	2.70	2.67	2.65	2.62	2.59	2.56	2.59	2.62	2.64	2.67	2.70
LIGNITE (7)	$/TON	13.94	14.05	14.16	14.28	14.39	14.52	14.65	14.78	14.92	15.06	15.19	15.32	15.51	15.76	16.01	16.27	16.53	16.79
	$/MBTU	1.17	1.18	1.19	1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.28	1.29	1.30	1.32	1.35	1.37	1.39	1.41
IMP. COAL (8)	$/TON	50.00	50.90	51.82	52.75	53.70	54.00	54.27	54.54	54.81	55.09	55.36	55.64	55.75	56.03	56.31	56.59	56.87	57.16
	$/MBTU	1.89	1.93	1.96	2.00	2.03	2.05	2.06	2.07	2.08	2.09	2.10	2.11	2.11	2.12	2.13	2.14	2.15	2.17
DOMES. GAS (9)																			
COST	$/MBTU	2.00	2.02	2.04	2.06	2.08	2.10	2.12	2.14	2.17	2.19	2.21	2.23	2.25	2.28	2.30	2.32	2.35	2.37
VALUE	$/MBTU	4.50	4.55	4.59	4.64	4.68	4.73	4.78	4.82	4.87	4.92	4.97	5.02	5.07	5.12	5.17	5.22	5.28	5.33
BURMA GAS (10)																			
MIN COST/LOW GAS FLOW	$/MBTU	2.26	2.28	2.31	2.33	2.35	2.38	2.40	2.42	2.45	2.47	2.50	2.52	2.55	2.57	2.60	2.62	2.65	2.68
MIN COST/HIGH GAS FLOW	$/MBTU	1.75	1.77	1.79	1.80	1.82	1.84	1.86	1.88	1.89	1.91	1.93	1.95	1.97	1.99	2.01	2.03	2.05	2.07
VALUE	$/MBTU	4.50	4.55	4.59	4.64	4.68	4.73	4.78	4.82	4.87	4.92	4.97	5.02	5.07	5.12	5.17	5.22	5.28	5.33
MALAY GAS (11)																			
MIN COST/HIGH GAS FLOW	$/MBTU	2.37	2.39	2.42	2.44	2.47	2.49	2.52	2.54	2.57	2.59	2.62	2.64	2.67	2.70	2.72	2.75	2.78	2.81
VALUE	$/MBTU	4.50	4.55	4.59	4.64	4.68	4.73	4.78	4.82	4.87	4.92	4.97	5.02	5.07	5.12	5.17	5.22	5.28	5.33
LNG (12)																			
COST	$/MBTU	3.87	3.82	3.87	4.00	4.13	4.26	4.40	4.55	4.50	4.46	4.41	4.37	4.31	4.36	4.40	4.45	4.50	4.54
VALUE	$/MBTU	4.50	4.55	4.59	4.64	4.68	4.73	4.78	4.82	4.87	4.92	4.97	5.02	5.07	5.12	5.17	5.22	5.28	5.33

Notes:

(1) CIF Prices. Includes FOB 1990–prices projected by IECIT at the World Bank plus $1.50/bbl for freight and insurance.
(2) MontBelvieu reference prices, Platts Oilgram Price Report, Volume 71, No.81, Tuesday, April 27, 1993, plus US$4 per barrel for ocean transport and insurance.
(3) Gasoline to crude ratio (CIF) averaged 1.51 during the period covering the years 1989, 1990 and 1992 (IECIT, World Bank).
(4) Kerosene/Jet fuel to crude ratio (CIF) averaged 1.50 during the period covering the years 1989, 1990 and 1992 (IECIT, World Bank).
(5) Gasoil/Diesel to crude ratio (CIF) averaged 1.52 during the period covering the years 1989, 1990 and 1992 (IECIT, World Bank).
(6) Fuel oil to crude ratio (CIF) averaged 0.83 during the period covering the years 1989, 1990 and 1992 (IECIT, World Bank). Price is for high sulphur (3–3.5%) fuel oil.
(7) Mission estimates based on EGAT's production costs at Mae Moh (calorific value of 3,000 kcal/kg).
(8) Mission estimates based on Bank's FOB projections plus $7 for freight & insurance (calorific value of 12,000 btu/lb), plus $6 for inland handling.
(9) Mission estimates based on weighted ratio of Unocal and Bongkot delivered at Bangkok.
(10) Cost – Economic cost delivered at Bangkok with no depletion allowance (low flow, 300 mmcfd; high flow, 500 mmcfd).
Value – Gas netback value at Bangkok, weighted average power and industry.
(11) Cost – Economic cost delivered at Khanom, at 150 mmcfd, with no depletion allowance.
Value – Gas netback value at Khanom for power and industry.
(12) Cost – CIF at terminal, Bangkok. Price increase according to the crude oil price.
Value – Gas netback value at Bangkok, weighted average power and industry.

THAILAND
FUEL OPTION STUDY

Table A3.1: Domestic Energy Prices
(January 1993)

	1991 Share of Total Oil Consumption	CIF	Ex-Ref	Tax Excise & Municipal	Oil Fund	Cons. Fund	Average holesale Price	VAT	Wholesal + VAT	Market Margin	VAT	Retail Price	Intl. FOB Oil Prod. Prices (9)
LPG (Baht/kg) (1)			7.42	2.39	-2.11	0.00	7.69	0.54	8.23	2.36	0.17	10.75	
LPG (Baht/lt)	0.076		4.04	1.30	-1.15	0.00	4.19	0.29	4.48	1.28	0.09	5.86	5.36
PREM.GASOLINE (Baht/lt)	0.047		4.09	3.36	0.03	0.07	7.55	0.53	8.07	1.28	0.09	9.44	4.40
UNLEADED GASOLINE (Baht/lt)	0.030		5.27	2.58	0.03	0.07	7.95	0.56	8.51	0.80	0.05	9.36	4.40
REG.GASOLINE (Baht/lt) (2)	0.082		3.54	3.36	0.03	0.07	6.99	0.49	7.48	1.07	0.07	8.62	4.32
KEROSENE (Baht/lt)	0.109		4.25	3.30	0.03	0.07	7.65	0.54	8.18	0.76	0.05	9.00	4.24
DIESEL (Baht/lt) (3)	0.406		4.26	2.31	0.03	0.07	6.67	0.47	7.13	0.80	0.06	7.99	4.22
FUEL OIL (Baht/lt) (4)	0.250		2.14	0.50	0.03	0.07	2.74	0.19	2.93	0.46	0.03	3.42	1.96
WEIGHTED OIL AVG.(Baht/lt) (5)	1.00		3.67	2.03	-0.06	0.06	5.71	0.40	6.11	0.79	0.06	6.96	3.77
ELECTRICITY (Baht/Kwh) (6)													
Industrial- MEA Area												1.60	
Industrial- Outside MEA												1.57	
Residential- MEA Area												1.81	
Residential- Outside MEA												1.40	
LIGNITE (Baht/ton) (7)			579	21								600	
COAL (Dollar/ton) (8)		50		5								55	

Source: Thailand

Notes:

(1) LPG figures refers to both large and small size.
(2) Figures for regular gasoline refer to gasoline with 83 RON.
(3) Figures refer to high speed diesel, 1% sulfur content.
(4) Figures refer to fuel oil 1500.
(5) This figure is computed by multiplying the price of each product by its share.
(6) Electric tariffs correspond to average tariffs reported by DEA in "Electric Power in Thailand 1991".
Note that since tariffs have not changed since 1991, the figures for that year are currently valid.
(7) The tax figure for lignite corresponds to a Royalty charge. Figure under EX-REF corresponds to production cost.
(8) CIF figure for coal includes $7 for freight and insurance and $6 for handling. The 10% tax charged corresponds to an import duty which is applied to the CIF price.
(9) These figures correspond to Singapore and MontBelvieu markets as reported in "Platt's Oilgram Price Report", Vol. 71, No. 81, April 27, 1993

THAILAND

FUEL OPTION STUDY

Geology and Petroleum Potential of Thailand and Adjoining Basins

Thailand's Basins

1. **Offshore**. Two areas offshore Thailand have potential for gas and possibly oil in commercially viable quantities. By far the more significant at this time is the Gulf of Thailand. The Thai portion includes several present day sedimentary basins (as contrasted to areas which may have been basins in the geologic past but which have been diminished by regional uplift and subsequent erosion). These basins are: Chumpon (West Kra) Basin; Songkhla (East Kra) Basin; Pattani Trough; and the northern end of the Malay Basin. These basins are similar in most respects. They were formed as extensional rift basins along highly active lateral fault systems. They are filled with Cenozoic Age clastic sediments (sends, silts, and shales) during the Paleocene to Pleistocene Epochs, i.e., the last 60 million years. The sedimentary environment was principally non-marine with near shore fluvial, swamp, and lacustrine (lake and lagoon) deposits dominant. Thin coal seams are common. The basins in the Gulf of Thailand are separated by intervening highs or ridges where Cenozoic sediments are thin due to non-deposition and/or erosion and unconformably overlie older sediments of Mesozoic and/or Paleozoic age and in some areas volcanic terrain or crystalline basement.

2. The fault movement which formed these basins has persisted through the Cenozoic but has diminished over time with the Pleistocene and Recent deposition showing little effects of the fault movement. During most of the Cenozoic, movement continued on the lateral faults and the structural forces within each basin alternated between compression (uplift and folding) and extension (subsidence and sag). As each of these forces occurred, in turn the preceding structure was overprinted with the later movement. At present each basin is paradoxically characterized by low relief features (both highs and lows) which are highly faulted (normally extensive faulting is associated with high relief). Various aspects of the structural geometry suggest that the latest movements were primarily extensional.

3. With respect to hydrocarbons prospects, the basins in the Gulf of Thailand are all gas prone. The only significant oil discovered thus far is in the southeastern portion of the Malay Basin (offshore peninsular Malaysia) and even in this area gas remains a major component. Isolated oil discoveries have been made in the Chumpon Basin (from pre-Cenozoic carbonates), the Songkhla Basin (in Cenozoic clastic which appears to be non-commercial) and in the Pattani trough notably in reservoirs in the shallower part of the Cenozoic section. A recent oil discovery, by Maersk et al, in the northern Pattani trough (Tantawan-1) has the potential for becoming significant. High crustal heat flows, associated with lateral fault tectonics, appears to have placed the bulk of the most prospective Cenozoic interval in the over mature gas/condensate realm. The high heat flow regime interacting with the pre-Cenozoic limestones ($Ca\ CO_3$) also appears to have generated significant quantities of carbon-dioxide gas (CO_2) which is associated with the hydrocarbon gas.

4. The ten gas fields (Erawan in Unocal I; Baanpot, Satun, Platong, and Kaphong in Unocal II; Funan, Jakrawan, Trat, and Surat in Unocal III; and Bongkot), and six unevaluated discoveries (Pladang in Unocal II; Pakarang and Gomin in Unocal III; Pailin and Moragot in Unocal 12/27; and Tantawan), as well as the approximately thirteen fields and unappraised discoveries in the northwestern portion of the Malay Basin offshore peninsular Malaysia have strikingly similar characteristics. The gas is reservoired in sandstones of the several types associated with river and river mouth, lacustrine and shallow marine systems, i.e. fluvial-deltaic. Reservoirs in this depositional realm (predominantly channel fill and bars) are limited in extent and are further subdivided by faulting. In any given area scores to hundreds of individual reservoirs are productive. These may vary from just a few acres to 2000 acres or more in areal extent but most are relatively small. Traps are formed by fault closures, sand lenses, and anticlinal trap, with high side of fault closures being predominant. The small size and complexity of traps requires a concentrated three-dimensional seismic survey to assist in the drilling of optimally located wells, i.e. the most reserves tapped with the fewest penetrations.

5. The salient points, given these geologic parameters, are that individual fields contain an abundance of individual reservoirs of varying size, shape, and thickness, and that most individual reservoirs are small. When placed on production, each reservoir depletes rather quickly. Since each production well may penetrate from three to twenty plus reservoirs, workover recompletions are commonly frequent. This, when coupled with the large number of platforms and wells required, makes both the cost of development and the cost of production relatively high (considerably more than is normal for comparative field reserves).

6. Elsewhere, the Thai portion of the Andaman Sea shelf containing perhaps several basins has been lightly explored and potential for hydrocarbons in commercial quantities may exist but carries a high degree of geologic risk. A recent discovery offshore Myanmar about 250 Km north of the Thai border has upgraded the outlook for the offshore area west of the southern Thai peninsula. Details of this discovery, made by Texaco in early 1992, are sparse but it appears that a substantial gas reservoir was found in an Oligo-Miocene (mid Cenozoic) turbidite sand, i.e. submarine fan deposit, with a thickness reputed to be in excess of 100 m (330 feet). Further exploration and development will be required to determine its significance as well as any effect it may have regarding Thai potential in the Andaman Sea.

7. **Onshore**. The petroleum geology of onshore Thailand falls into two distinct categories. These are a series of north/south trending Cenozoic Basins in the western half of mainland Thailand, which became present day inter-montane basins in the north, and the large Khorat Basin in the northeast which is filled with older Mesozoic and Paleozoic strata. The Cenozoic basins in the west include the North Bangkok area (Suphan Buri and Kamphaeng Basins), the Petchabun Basin, the Phitsanulok Basin, and the Lampang, Chingmai, Phrae, and Fang intermontane basins. While these Cenozoic basins are similar in most respects to those in the Gulf of Thailand, they appear to be oil prone. A major oil field, Sirikit, plus seven minor fields which have been found in the Phitsanulok Basin, to date are the most prolific of the onshore basins in Thailand. Small and relatively insignificant oil fields have been found in the Suphan Buri, Kamphaeng, Petchabun, and Fang Basins. All of these produce from Oligo-Miocene sand reservoirs deposited in a non-marine, predominantly lacustrine environment. Individual reservoirs are small. The large field, Sirikit, is typified by a large number of stacked reservoirs and a relatively thick and extensive source rock of Oligo Miocene lacustrine shales. Additional potential for

hydrocarbons in the onshore Cenozoic Basins is obvious but the bulk is likely to be found as small oil fields with marginal commerciality due to the limited area and thickness of the Cenozoic section. Several more moderate size accumulations approaching the Sirikit level are possible but not likely.

8. The Khorat Basin covers a large portion of northeast Thailand. The basin sediments are comprised of a thick section of Mesozic Cretaceous red beds (oxidized sandstone and shale) with relatively thin interbedded evaporites (anhydrite, gypsum, and salt). This interval has minimal petroleum potential unless sourced by non-oxidized beds from below. The Cretaceous red beds unconformably overlie early Mesozoic and Paleozoic strata, in particular an extensive and thick blanket of upper Paleozoic Permo-Carboniferous limestone and dolomite. It is this deep pre-Cretaceous section that appears to be the most petroliferous. This section will likely be subdivided into several predecessor basins as exploratory activity progresses. The pre-Cretaceous section appears to be structured by fault blocks, with high blocks prospective and hydrocarbons sourced from the low blocks, with Triassic shales, best developed in the lows providing the source. The Permo-Carboniferous limestone is the only reservoir found to date. It is apparently highly fractured, as noted in surface outcrop and in the performance of the only field developed to date, i.e. Namphong gas field. Due to depth of burial and generally elevated heat regime, the Khorat Basin is likely to be gas prone. Prospecting is difficult due to the overprint of Cenozoic structuring by compressive forces obscuring the structure of the underlying fault blocks. Reserves and field performance are difficult to evaluate due to the fractured reservoirs in which the bulk of the void space (porosity) consists of fractures. Gas recovery may be lowered by active water drives resulting in vertical water coning near the producing wells. Because of its size, the Khorat Basin has a large gas potential but it will take many years to fully evaluate.

9. Three gas discoveries have been made in the Khorat Basin. The Namphong field is the only commercial development. The two other fields are not currently considered commercial. Exploration at relatively low levels is being conducted over a sizeable portion of the basin. It is interesting to note that the Nang Nuan oil discovery in the Chumpon Basin in the Gulf of Thailand is productive from a similar fractured pre-Cenozoic limestone. The Nang Nuan field evaluation is fraught with the same problems of evaluation, i.e. water coning near the well bore.

Adjoining Basins

10. **Malaysia**. Most of the Malay Basin is located off the east cost of peninsular Malaysia. As noted in para. 1, the northern end of this basin extends into Thai waters which includes the Bongkot field and two unevaluated discoveries in the Thai/Malay Joint Development Area (JDA). Some 13 gas fields with reputed reserves of approximately 20,000 bcf have been found to date in that portion of the Malay Basin immediately south of the JDA. Only one of these, Jerneh field, has been developed to date. The general geology is similar to that in the several basins further north in the Gulf of Thailand. Apparently the individual sand reservoirs are somewhat more extensive and the structures somewhat less faulted that in Thailand. This may be due to the greater marine influence on deposition and the greater basin area (principally width) resulting in less intense structuring. Thus rapid depletion of individual wells is expected to be less severe than in the basins to the north. However, these observations are based largely on geologic perceptions since there has been no gas field production in this part of the Malay Basin prior to 1992.

11. **Viet Nam and Cambodia**. Viet Nam territory, both undisputed and disputed, covers the northeastern portion of the Malay Basin, immediately to the east and southeast of Thai waters. While discoveries in Malaysia and well-defined prospects in Thailand adjoin areas of Viet Nam claim, essentially no exploration activity has yet taken place in this part of offshore Viet Nam. Similarly Cambodia claims extend into the eastern flank of the productive Pattani Trough and the northernmost portion of the Malay Basin. In Thailand Unocal's Kaphong (producing) and Trat (not yet on production) fields adjoin Cambodia claims in the Pattani Tough and well-defined prospects in the Bongkot area adjoin Cambodia claims in the Malay Basin. This latter area is also claimed by Viet Nam and overlap Thai claims in both basins. No significant variation in the geology and potential of the Pattani Trough or Malaya Basin is expected in either the disputed or undisputed territory claimed by Viet Nam or Cambodia. Due to lack of exploration activities in this portion of these countries it is difficult to ascertain precisely the basin limits east and southeast of Thailand.

12. **Myanmar**. The principal potential source for import gas from Myanmar is the Martaban gas field in the Andaman Sea offshore south west Myanmar (originally called the "D" structure). This field contains gas in an Upper Cenozoic Miocene limestone reef (or bank) situated on and confined to an underlying high block. Three wells capable of producing gas at high rates have been drilled on the Martaban feature which is delineated by a seismic survey. Further evaluation is currently taking place and barring unforeseen results, development should begin by late 1994. The structure of the field is a build-up organically derived limestone on an underlying high block (probably a subsea topographic high at the time of deposition). The limestone reservoir is high quality with 25-30% matrix porosity and up to 95% gas saturation. Due to the lack of structural stress, fracturing is expected to be inconsequential. Given the excellent reservoir characteristics, the development investment (in terms of numbers of platforms and wells) should be relatively low, in contrast to the Gulf of Thailand. The main possible drawback is the likelihood of an active bottom water drive which should not be serious in terms of water coning but would maintain formation pressures and limit ultimate recovery vs. that possible from pressure depletion.

13. The recent Texaco discovery described in para. 6 may also lead to potential gas imports. This discovery is located offshore almost due west of Bangkok.

THAILAND

FUEL OPTION STUDY

Hydrocarbon Reserves, Production and Import Potential

Introduction

1. Data for the forecast of reserves and production, as well as guidance for its use, was provided by the Department of Mineral Resources (DMR), the Petroleum Authority of Thailand (PTT) and its exploration and production subsidiary, PTTEP. Data was also obtained from the several oil companies operating in Thailand either directly, or indirectly through the forenamed government institutions.

2. This forecast is based on several factors: (a) current reserve estimates; (b) indicated potential for future reserve additions associated with the existing discoveries and with defined analogous prospects within the hydrocarbon producing sedimentary basins; (c) current investment plans by the operating companies; and (d) the timing of new increments of production based on these investment plans.

3. The reserve data used is shown on Table I attached. At present, it is estimated that 377 million barrels of oil and condensate and 8,413 billion cubic feet of natural gas have been discovered. Of this, some 132 million barrels of liquids and 1,958 billion cubic feet of gas have been produced through 31 December 1992. The remaining 245 million barrels of oil and 6,455 billion cubic feet of gas are proved and risked probable reserves. In addition, another 607 million barrels of oil and 14 billion cubic feet of gas may be added in the future, from possible reserves. The bulk of this is located offshore the Gulf of Thailand, i.e., 72% of the liquids and 90% of the gas.

4. The production forecast is presented with three scenarios: (a) Firm, that forecast based on currently established proved and risked probable reserves; (b) Most Likely, that forecast which adds risked possible reserves to the firm category and for which the operating companies have firm investment programs underway or in their near term plans; and (c) High, that forecast which further includes risked possible reserves and/or future reserve additions from clearly identified potential, i.e., unappraised discoveries and notional potential associated with defined analogous undrilled prospects within the limits of established productive basins. The estimates of future production of petroleum liquids and natural gas in the several scenarios are shown on Table II (Liquids), Tables III (Offshore Gas), Table IV (Domestic Gas) and Table V (Total Domestic and Imported Gas). For planning purposes, it is suggested that realistic expectations of future supply lie in the range between the Most Likely and High scenarios.

5. The bulk of the domestic offshore gas contains a significant liquid fraction after condensate removal, i.e., wet gas. Onshore S-1 gas production is also wet. Onshore Namphong gas

and import gas from Myanmar is dry and expectations are that Malaysian imports will have had liquids removed prior to transfer at the border. At present, dry gas available to the industry and power sector is equal to 82% of gross production after subtracting 2% consumed in operations and 16% shrinkage due to removal of liquids during processing. In the future this shrinkage will be reduced to 12% of gross production, as drier gas from Bongkot, JDA and imports are phased in. Thus, 2000-2600 mmcfd raw gas availability will translate to 1,750-2,275 mmcfd dry gas available for industry and power utilization. The heat value of this dry gas, currently 970 btu/cubic foot, will vary from 940-990 btu/cubic foot, depending on the mix of the gas source at any given time.

6. In summary, Thailand should plan for domestic liquids production of 50,000 bpd but no more than 85,000 bpd. Domestic gas production is expected to plateau at 1400 mmcfd but no more than 2,200 mmcfd. Likely imports range from 650 mmcfd, all available for industry and power of an average of 1000 btu/cubic foot.

Reserves

7. **General.** Reserves of oil, gas, and condensate are those volumes remaining to be produced that can be recovered under current economic conditions (net price vs cost) with currently available technology. The reserves are normally categorized with varying degrees of certainty with respect to both their existence and to the economics of recovery. Therefore, proven reserves are essentially certain to exist and can be recovered with current economics and technology. Probable reserves are those volumes that are likely to exist (reasonable certainty) which can likely be recovered with current economic parameters. Possible reserves are those which are known to exist but where volumes are less certain due to insufficient data or where economic development criteria is not fully established. Identified potential are notional estimates of reserves which may accrue in the future, based on either unappraised discoveries or on well-defined prospects similar to fields in the same area with similar geologic attributes.

8. Under ideal conditions reserves can be measured volumetrically in-place using various standard, e.g., American Petroleum Institute (API) guidelines which more or less establishes the proper category of certainty. The volumetric method is particularly applicable where development is clearly economic and reservoir configurations are relatively simple. Even under these conditions, reserves remain an estimate which can be refined as development and production proceed, i.e. reservoir geometry and production behavior (recovery percentage) becomes more apparent. Since proved reserves are conservatively assigned, they normally grow during the life of production; improved technology and incremental economics normally play a positive role as well. Reserves assigned as probable normally remain fairly constant, being diminished as they are upgraded to proved, and being replenished as possible reserves are upgraded to probable. Possible reserves tend to swing widely over time as some are upgraded, some prove to be non-existent (or non-commercial), and at times are replenished by discoveries from the identified potential.

9. In a practical sense proved reserves accrue as the result of development, i.e., booked as reserves following investment. Most often development investments are based on proved plus probable reserves, rather than proved reserves alone. Forecasting and planning for future investment on the

other hand must account for possible reserves and identified potential based on historic, statistical or judgmental inputs.

10. **Thailand's Petroleum Reserves**. Due to the rather unique geology in Thailand conventional volumetric measurement of in-place reserves are impossible. This is due to the vast multitude (many thousands) of individual reservoirs in the Tertiary strata in the Gulf of Thailand and onshore, as well as the highly fractured reservoirs of the pre-Tertiary carbonates, e.g., Namphong onshore and Nang Nuan offshore. Reserve estimates in Thailand are based on statistical distribution of reservoirs rather than on direct measurement and are particularly sensitive to economic parameters, i.e., concentration of reservoirs and product price. Thus, even where oil and gas is found, a sufficient area of reservoir concentration, based largely on net pay interval/well, must be defined to establish commercial reserves and permit an estimate of proved reserves. Where this concentration appears likely to be established, probable reserves are assigned. Where the required concentration remains questionable, requiring a number of additional wells, only possible reserves can be attributed. Accordingly, oil and gas reserves in Thailand are highly price sensitive: With higher prices, areas with lower concentrations of reservoirs can be commercially exploited, and vice-versa; all due to the vast number of productive reservoirs and the high cost of tapping the majority of them. Table I represents an attempt to place reserves of oil and gas as reported to the DMR into a consistent format.

11. DMR, for the Unocal fields, reports its reserves in three categories: (a) Proven reserves; (b) risked probable reserves, which are based on actual probable reserves times 0.6 (hence actual probable reserves are reduced by 40%); and (c) risked possible reserves, which are based on actual possible reserves times 0.3 (hence actual possible reserves are reduced by 70%). Table I shows the proven and risked probable reserves (the sum of which provides the "firm" reserves) according to Unocal's concept. However, the "possible" and "identified potential" reserves are shown as actual unrisked reserves (without reduction). To obtain "most likely" reserves, the firm reserves are added to 30% of remainder of probable reserves (namely, 30% of the 40%), plus 30% of the actual possible reserves. For "high" reserves scenario, it is the same as the Most Likely reserve scenario except (i) the percentage is increased to 50% (instead of 30%); and (ii) the Identified Potential reserves are also included. Thus, Unocal I is estimated to have a Firm reserves of 1,200 bcf, which is the sum of proven reserves (1,000 bcf) and 60% of the probable reserves (200 bcf). The Most Likely reserves for Unocal I is the sum of 1,200 bcf (Firm reserves) plus 30% of the remainder of probable reserves (136 bcf) and 30% of the possible reserves (2,700 bcf). Hence, the Most Likely reserves of Unocal I is 2,050 bcf. For the High reserve scenario, the percentage is increased to 50%. Hence, the High reserves scenario for Unocal I is the sum of Firm reserves (1,200 bcf) plus 50% of the remainder of probable reserves (136 bcf) and possible reserves (2,700 bcf) and Identified Potential reserves (zero, in this case), which equals to 2,617 bcf. The same methodology has been used for Unocal II and III.

12. TOTAL reports for the Bongkot field 1,860 bcf proven, no probable, and 2,761 bcf possible (may be total). Since this reporting varies from the standard that DMR uses for Unocal fields, Table I uses the 1989 reserves certification data by consultants, D & M; namely, 1495 bcf proved, 675 bcf probable, and 590 bcf possible. Since this is a conservative estimate, the probable estimate is considered commensurate with Unocal risked probable and the possible estimate is accepted as is. In addition, in the case of Bongkot, at least four highly promising prospects have been identified with a

new relatively dense 2-D seismic grid. These prospects have been arbitrarily assigned an identified potential of 2500 bcf, more or less in line with TOTAL's current thinking.

13. Unocal reports no reserves as yet for Block 12/27. However, PTTEP, with assistance from British Petroleum (a part owner) suggests 1,682 bcf probable reserves, which is incorporated in the DMR data. Table I, however, follows the consultants' estimates, namely that the field has about 90 bcf of proven reserves, 65 bcf of risked probable and 1,300 bcf of possible reserves. It should be noted that DMR for planning purposes estimates 1000 bcf of possible sales gas, roughly equivalent to the 1682 bcf probable (or 3000 bcf possible). Unocal has delayed reporting reserve volumes pending the outcome of sales contract negotiations. In view of the two discoveries (Pailin, a southern extension of the Erawan field and equal in area, and Moragot) plus three additional high quality undrilled prospects, the future potential of block 12/27 could reach a value of 2982 bcf gas.

14. Other offshore reserves include several minor oil discoveries plus the Maersk block (immediately north of Unocal I, II, and III) where a significant discovery was made in 1992. The Maersk Tantawan discovery tested oil at the rates of up to 3,215 bpd from four sandstone reservoirs (total net thickness 106 feet) and tested gas at 0.5 mmcfd from two reservoirs (total net thickness 47 feet) with six additional zones (most likely gas) untested. Possible reserves of 22 million barrels and 92 bcf have been submitted to the DMR for this discovery. However, in Table I, identified potential reserves of 85 million barrels of oil/condensate and 1,400 bcf of gas are arbitrarily assigned to the Maersk block in consideration of the several identified prospects on this block. Two of the prospects will be drilled in 1993. In addition, 1 million barrels proved oil, 2 million barrels probable oil, and 3 million barrels possible oil, and 8 bcf possible gas is attributable to the Shell Nang Nuan A and B discoveries, as carried by the DMR (DMR omits the possible gas). Possible reserves carried by the DMR for the L structure (British Gas) and the Songkhla and Bua Ban fields (Premier) are considered non-commercial and omitted from Table I.

15. The Thai-Malay Joint Development Area (JDA) has been assigned 3000 bcf of possible gas reserve by the DMR based on two discoveries made in the early 1970s. The existing 2-D seismic grid is too wide to adequately map the area and no reserves are shown on Table I for the JDA. The 3000 bcf is however a reasonable notional estimate for identified potential which is credited on Table I. It should be noted that the DMR possible reserve figure came from an in-house assessment of potential using probability analyses.

16. The gas liquids reserve for all offshore areas shown on Table I are actual submissions or based on established liquids/gas ratios where possible gas reserves have been upgraded.

17. All onshore reserves submitted to the DMR have been incorporated on Table I. Only Shell's S-1 Block (Sirikit and satellite fields) and Esso's Namphong gas field are of any consequence at this time.

18. Discrepancies noted between Table I and the reserves reported by DMR are more due to allocation by category of reserves rather than any difference in substance. While the reserve estimates used in Table I are not necessarily more correct than the DMR reserve data, they are believed to be more consistently stated.

Domestic Sources of Petroleum Liquids and Natural Gas

19. **Offshore**. The Pattani Trough Basin and the Malay Basin (the northwestern portion extends into Thailand) in the Gulf of Thailand have proved to be prolific sources of natural gas and associated liquid condensates. The combined potential of these basins in Thailand as currently understood is in the order of 16,500 bcf of natural gas and 500 million barrels of condensate plus minor amounts, 40 million barrels, of oil. The average condensate ratio is about 26 barrel/million cubic feet ranging in richness from 12-40 barrels/mmft^3.

20. The largest source of gas and condensate is the Unocal area covered by Gas Contracts I, II and III with about 7150 bcf and 287 million barrels expected to be produced under a most likely scenario. This area is also the most developed at present with production dating back to 1981. At present Unocal has 41 producing platforms with over 350 producing wells (the number of producers vary continuously as wells are shut-in for tests, undergoing or awaiting workover, or new wells are placed on production), yielding 750 mmcfd gas and 27,000 bpd of condensate. Unocal has 35 additional platform locations with proved reserves (5 of which are currently installed with development underway); 32 additional platform locations are credited with probable reserves (needs at least one additional appraisal well for confirmation to proved); and 29 additional potential platform locations with possible reserves (needs several additional appraisal wells to confirm). Unocal has firm plans to invest up to $1 billion over the next 5 years in appraisal wells, platforms, and development wells to develop this potential, with continuing investments of about US$200 million per year thereafter. This investment program is predicated on the expectation of a second Gulf gas trunkline available by early 1996. By field, existing and proposed platform locations are distributed as follows (from this data the status of Unocal's 13 field discoveries is self evident):

Field (Contract Area)	Product Platforms	Proven Platforms	Probable Platforms	Possible Platforms
Erawan (I)	16	6	4	--
Baanpot (II)	3	1	2	2
Satun (II)	10	1	4	2
Platong (II)	5	1	2	--
Kaphong (II)	2	--	2	--
Pladang (II)	--	--	3	--
Gomin (III)	--	--	3	--
Jakrawan (III)	--	12	4	1
Funan (III)	5	8	3	1
Pakarang (III)	--	--	3	2
Trat (III)	--	2	1	13
Surat (III)	--	1	3	3
Dara (III)	--	--	--	2
TOTAL	41	32	34	26

21. The second largest source of gas and condensate is TOTAL's Bongkot development area with about 4000 bcf of gas and 70 million barrels of condensate expected to be produced. The Bongkot

field is under active development and production and is expected to start in early 1994. TOTAL is installing three well platforms with 27 producing wells in the first phase of development and has firm plans to have 13 platforms and 120 wells later in the decade. This program will grow substantially if field extensions and new discoveries accrue as expected. TOTAL is encouraged by their 3-D seismic and early drilling results and has engaged DeGolyer and MacNaughton to provide annual reserve certification updates. Current expectations are that they will be able to add at least about 1000 bcf to Bongkot field reserves and raise production to 500 cfd by the year 2000.

22. The third largest source of offshore gas and condensate is Unocal's Block 12/27 lying immediately south of Unocal Areas I, II, and III in the southernmost portion of the Pattani Trough Basin. Ultimately, some 2000 bcf of gas and 40 million barrels of condensate are expected to be produced. The major field on this block, Pailin, is under active appraisal at this time. The field area has been covered by a recent 3-D seismic survey and six productive wells have been drilled. One rig is currently active. Another field, Moragot, has been discovered with two successful gas wells. Additionally one minor oil discovery has been made and four dry holes have been drilled on this block. At least three additional high quality prospects remain to be drilled in the future. The Pailin field is on the southern extension of the Erawan trend (Unocal Area I), presently the largest field offshore Thailand, and covers about the same area as Erawan. It is expected that Pailin will be declared commercial by end-1993 and production to start by 1998.

23. Oil and gas was discovered on the Maersk block, lying immediately north of Unocal areas I, II, and III, during 1992 with the completion of the Tantawan well. This discovery is very promising and a 3-D seismic survey is underway covering the Tantawan feature. Maersk plans to actively explore their block with two additional prospects to be drilled in 1993 and appraisal drilling at Tantawan slated to begin early in 1994. Depending on results of the appraisal activity, production could begin by 1998. At this early stage the Maersk block is expected to produce some 700 bcf of gas and 40-50 million barrels of condensate, but this could prove to be conservative.

24. Finally, a source of gas and condensate in offshore Thailand is expected to be the Thai-Malay Joint Development Area (JDA), area of conflicting boundary claims. Steady progress has been made in resolving the issues involved and an operating agreement between the parties involved will be concluded by early 1994. PTTEP representing the Thai interest, Petronas Carigali representing the Malay interest, and Triton Energy (USA) holding rights on a portion of the Malay interest, will be parties to the contract. The JDA Block, situated in the northern part of the Malay Basin covers 7,250 sq. kms. with conflicting claims by Cambodia and Viet Nam affecting about 10% of the block in the north and east portions. The JDA Block lies between the productive Bongkot block to the north and is abutted by three recent discoveries in Malaysia on the south made by Home Oil, Lasmo/Exxon, and Broken Hill Pty (Hamilton). These discoveries greatly adds to its prospectivity. Two gas discoveries, one each by British Petroleum and Exxon, were made in the JDA area in the early 1970s based on a rather widely spaced 2D seismic grid. Neither was considered commercial at that time. Future activities will be undertaken in accordance with the standard Malay Production Sharing Contract (PSC). This contract provides for a five-year exploratory period after which all areas not included in commercial discoveries will be relinquished. The ensuing five-years is the development/marketing period, following which all areas without a production/sales contract will be relinquished. Thus the PSC inhibits early production start since all exploration and development must take place in the first 10

years to the point of reserve certification, contract negotiation and pipeline planning. Therefore, production start, if justified, is not likely to be prior to 2000. The group hopes to start with a closely spaced 2-D seismic gird in 1994, begin exploratory drilling in 1995, followed by a 3-D seismic survey over initial discoveries in 1996-97, and appraisal drilling plus possible further exploratory wells in 1997-98, in order to determine areas of retention. Based on the favorable situation of the JDA block, discoveries on trend in both directions, the two early discoveries, and the general prospectivity seen on the early seismic, some 1,500 bcf plus 30 million barrels of condensate is anticipated from the JDA.

25. **Onshore**. Oil and gas has been found rather widespread over onshore Thailand ranging from the Lower Chao Prya Basin near Bangkok in the south to the intermontane Fang Basin in the northern reaches of the country and extending east into the Khorat Basin. However, only two areas have any current significance. These are the Shell S-1 block (Sirikit and satellite fields) in the Sukhotai Basin in Central Thailand and the Esso Namphong gas field in the Khorat Basin. The Sirikit field is the largest oil field in Thailand and is fully developed. Sirikit is expected to yield about 100 million barrels of oil and 320 bcf of gas (about 270 bcf produced as solution gas and 50 bcf produced as gas-cap blowdown). The S-1 block has been thoroughly explored with four small additional satellite field discoveries made. It has minimal additional potential except that a water injection program may add 35 million barrels of oil and 90 bcf of gas to the Sirikit field if it proves feasible. The Namphong gas field is also fully delineated and expected to produce 540 bcf of dry gas. An additional 150 bcf gas may be recovered from the smaller Esso discoveries, PruHorm and Dong Mun, should these prove to be commercial.

26. **Production Forecast**. The forecast of production profiles shown on the respective Tables II-V are based on the combination of actual, stated, and notional plans of the operators, and restricted by the reserves using uniform treatment of the reserves. The production scenarios follow the reserve scenarios in the definition, in that the Firm forecast is restricted by the proved plus risked probable reserves. The Most Likely forecast is restricted by the proved and risked probable reserves plus 30% of the upgraded possible reserves. The High forecast is restricted by the proved and risked probable reserves plus 50% of the upgraded possible reserves and the notional identified potential.

Potential Pipeline Gas Imports from Neighboring Countries

27. Some of the countries bordering Thailand may have gas reserves likely to exceed domestic requirements that may be available for import into the Thai market. Potential surplus gas reserves exist today in Malaysia and Myanmar and are likely to be developed in Cambodia and Viet Nam. Complex international agreements, lengthy sales contract negotiations, costly infrastructure investment (pipelines, and in the case of Cambodia and Viet Nam basic exploration and development), are required for Thailand to secure access to this gas.

28. **Malaysia**. Gas reserves in the Malay Basin offshore peninsular Malaysia are quite large, reputedly 27,500 bcf in the proved and probable categories. Approximately 7,500 bcf is in association with oil fields either as solution gas, gas cap, or in interlayered gas-only reservoirs. Gas produced in association with oil has a clear market priority. It is also rich in liquids. The bulk of the gas used domestically or exported to Singapore today is produced as a by-product of the oil. Gas is

gathered at offshore platforms in the Guntong, Bekok, and Sotong oil fields, as well as in the Duyong gas field, and transported to Kertih on the east coast of the Malay peninsula where liquids are removed and the dry gas utilized by thermal power plant, at Terengganu (near Kertih) and in the Kuala Lumpur area on the west coast as well as at Johore and Singapore in the south. During 1992, this gas was supplemented by gas from the Jerneh field (separate pipeline to Kertih), one of the largest of the 13 or so non-associated gas fields which contain the remaining 20,000 bcf of reserve. Jerneh, operated by Esso Malaysia Production Inc. (EPMI), is producing initially at the rate of 150 mmcfd. However, EPMI expects output to grow to 750 mmcfd by the end of the century. Plans are underway to develop the nearby Lawit gas field in the near future, also via separate pipeline to Kertih. To utilize this gas, Malaysia is planning to extend the existing pipeline north along the west coast from the Kuala Lumpur area to the Penang area and beyond to near the Thai border in southwestern peninsular Thailand. Preliminary discussions between Malay and Thai officials have suggested that some 150-300 mmcfd may be available for export to Thailand. Border delivery price is likely to become a source for protracted negotiations due to lengthy pipeline route envisioned (about 1000 Km, including 220 offshore and 780 onshore). A forecast start in 2001 is used for the High case on Table V. It could be somewhat later. The dependency of Malay plans to bring the gas to the border on an export sales contract is also unknown. This scenario requires an evolution in Malay thinking regarding gas development and export policy.

29. **Myanmar**. Plans for Myanmar imports are farther advanced. TOTAL, the operator, plans to drill two four-appraisal wells in the Martaban offshore field and finalize interpretation of the recently acquired 3-D seismic during 1993. They expect reserve certification by mid-1994 and to begin development immediately thereafter. While still tentative, the development program is expected to require four well-platforms and 20 wells. TOTAL's estimate for field investment is about US$380 million. The pipeline route has not been finalize as yet, either the Myanmar or Thai portion, but TOTAL's estimate costs around US$700 million for the main line and US$120 million for the Myanmar offtake line. These costs appear to be low. Current target date for gas delivery to Rachaburi, Thailand is 1998. The Most Likely forecast (Table V) calls for a proved plus probable reserve of 3,500 bcf producing at the rate of 400 mmcfd (300 mmcfd to Thailand and 100 mmcfd to Myanmar). The High forecast envisions a proved plus probable reserve of 5,000 bcf producing at the rate of 625 mmcfd (500 mmcfd to Thailand and 125 mmcfd to Myanmar). This reserves is supplemented by a recent offshore discovery made by Texaco reported to have the potential for up to 10,000 bcf potential. Myanmar imports, however, carry a political risks ranging from pipeline disruption by Burmese insurgents to the survivability of the military government in Myanmar.

30. **Other Imports**. Other imports are too remote at this time to be incorporated into the long range forecast. However, substantial potential for gas discovery in the disputed areas between Thailand, Cambodia, and Viet Nam, and undisputed portions of Viet Nam in the Gulf of Thailand is obvious. Unocal's Kaphong, Trat, Funan, and Gomin fields are adjacent to the Thai/Cambodia disputed area suggesting a potentially productive Thai/Cambodia area adjacent to Unocal areas II and III. The Maersk Tantawan discovery is also adjacent to the Cambodia claim. One of the Bongkot area prospects expected to be drilled in late 1993 or early 1994 is in close proximity to territory claimed by both Cambodia and Viet Nam, as well as Thailand. The Thai government should proceed with discussions with both the Cambodia and Viet Nam governments for the formation of "Joint Development Areas" (JDA) in these highly prospective areas. Seismic coverage, early 1970's 2-D data,

is available on these areas acquired by Thai licensees before disputes arose. It should also be noted that a Malay-Viet Nam JDA has been recently formed immediately southeast of the Thai-Malay JDA. Three prior discoveries by Malaysian licensees has been made, both oil and gas. Finally, Petrofina (Belgium) has a large license from Viet Nam in undisputed territory in the northeastern portion of the Malay Basin adjacent to the Bongkot and Thai-Malay JDA blocks. The Petrofina area is geologically well situated, and exploratory activities (2-D seismic) is expected to commence in the near future. All these areas mentioned are in close proximity to the Thai gas transportation system in the Gulf and considered attributable to it. While these areas are not expected to be developed until early in the next century, their potential gas supplies could supplement the present forecast and arrest the decline in gas availability forecast to occur post 2006.

THAILAND
FUEL OPTION STUDY

Table A5.1 - Petroleum Reserves - As of 01/01/93 (Mod. from DMR)

Gas: billion cubic feet (bcf)
Oil and Condensate: million barrel

	A		B		C		B+C		A+B+C		D		D	
Field/Area	Produced		Remain. Proved		Remain. risked Probable		Total Remain.		Total Disc.		Add. non-risked Possible		Ident. Potent. (non-risked)	
	Oil/Cond./Gas		Oil/Cond./Gas		Oil/Cond./Gas		Oil/Cond./Gas		Oil/Cond./Gas		Oil/Cond./Gas		Oil/Cond./Gas	
Unocal I	29	851	35	1000	7	200	42	1200	71	2051	95	2700	--	--
Unocal II	30	894	40	1200	5	150	45	1350	75	2244	125	3700	--	--
Unocal III	3	61	40	800	8	160	48	960	51	1021	270	5400	--	--
Bongkot	--	--	27	1495	12	675	39	2170	39	2170	11	590	45	2500
Unocal 12/27	--	--	2	90	1	65	3	155	3	155	45	1300	--	--
Maersk	--	--	--	--	--	--	--	--	--	--	--	--	85	1400
JDA	--	--	--	--	--	--	--	--	--	--	--	--	60	3000
Total Offshore	62	1806	144	4585	33	1250	177	5835	239	7641	546	13690	190	6900
Shell S-1	66	112	42	202	21	58	63	260	129	372	60	87	--	--
Namphong	--	40	--	260	--	100	--	360	--	400	--	305	--	--
Others	4	--	4	--	1	--	5	--	9	--	1	--	94	--
Total Onshore	70	152	46	462	22	158	68	620	138	772	61	392	94	--
Total Thailand	132	1958	190	5047	55	1408	245	6455	377	8413	607	14082	289	6900
(DMR)	132	1886	179	5740	62	2988	241	8728	373	10614	191	6935	--	--

Source: DMR and Bank mission estimates.
A and B - above are consistently reported by DMR. C - remaining probable reserves are risked (reduced by 40%) so that they may be combined with proved reserves as total remaining (Firm reserves). D - add. poss. reserves (not risked) are those attributable to potential growth of commercial fields. E - identified potential (not risked) includes estimates for either unappraised discoveries or fully mapped undrilled prospects.

THAILAND
FUEL OPTION STUDY

Table A5.2 - Domestic Liquids (Oil/Condensate) Production Forecast
(1,000 bpd)

	Unocal I-II-III			Bongkot			Unocal 12/27			Maersk	JDA	Others			Shell S-1 (Oil)			Total Thailand		
Year	Firm	M.L.	High	Firm	M.L.	High	Firm	M.L	High	High	High	Firm	M.L	High	Firm	M.L	High	Firm	M.L.	High
1993	27.1	45	65	1.4	1.4	1.4		-	-	-	-	1.5	1.5	1.5	20.7	20.7	20.7	50.7	68.6	88.2
1994	28.0	46	66	2.7	2.7	2.7		-	-	-	-	4.0	4.0	4.0	20.0	20.0	20.0	54.7	72.7	92.7
1995	24.5	45	66	4.5	4.5	4.5		-	-	-	-	4.0	4.0	4.0	19.0	19.0	19.0	52.0	72.5	93.5
1996	24.5	44	65	4.4	5.3	6.1		-	-	-	-	3.0	3.0	3.0	18.0	18.0	18.0	49.9	70.3	92.1
1997	24.5	43	64	4.3	5.2	6.1		-	-	-	-	2.0	2.0	12.0	17.0	17.0	18.5	47.8	67.2	100.6
1998	23.8	42	63	4.3	5.1	6.0	0.63	2.3	2.3	1.0	-	1.0	1.0	11.0	15.5	15.5	18.2	45.2	65.9	101.5
1999	23.5	41	62	4.1	5.0	6.6	0.63	4.6	5.8	2.0	-		-	10.0	13.0	13.0	17.1	41.2	63.6	103.5
2000	23.1	40	61	4.0	5.6	8.0	0.63	4.5	6.8	2.0	1.4		-	10.0	10.5	10.5	16.0	38.2	60.6	105.2
2001	22.8	39	60	3.8	5.3	7.5	0.63	4.4	6.6	2.0	1.8		-	10.0	8.5	8.5	15.6	35.8	57.2	103.5
2002	22.4	38	59	3.6	5.1	7.3	0.63	4.3	6.5	3.9	2.3		-	10.0	6.8	6.8	15.3	33.4	54.2	104.3
2003	22.1	37	58	3.5	4.9	7.0	0.63	4.2	6.3	3.8	2.7		-	10.0	5.4	5.4	15.0	31.6	51.5	102.8
2004	21.7	36	55	3.4	4.7	6.8	0.63	4.1	6.2	3.7	2.7		-	8.0	4.3	4.3	14.2	30.0	49.1	96.6
2005	21.0	35	50	3.3	4.6	6.5	0.63	4.0	6.0	5.4	2.7		-	6.5	3.4	3.4	11.6	28.4	47.0	88.7
2006	16.8	32	45	3.1	4.4	6.3	0.63	3.8	5.7	5.3	2.7		-	5.2	2.7	2.7	9.5	23.2	42.9	79.7
2007	13.4	25	40	2.4	4.2	6.0	0.63	3.6	5.4	5.1	4.3		-	4.2	2.2	2.2	7.9	18.6	35.0	72.9
2008	10.8	20	35	1.8	4.0	5.8	0.63	3.4	5.1	5.0	5.1		-	3.3	1.8	1.8	7.0	15.0	29.2	66.3
2009	8.6	15	30	1.4	3.1	5.5	0.63	2.6	4.8	4.8	4.8		-	2.7	1.4	1.4	5.8	12.0	22.1	58.4
2010	6.9	10	20	1.1	2.4	5.3	0.63	2.0	3.6	4.6	4.6		-	2.1	1.1	1.1	4.4	9.7	15.5	44.6
TOTAL mmbbl	133	231	352	21	28	38	3	17	26	18	13	5	5	42	63	63	93	225	344	582
After 2010	2	56	36	18	16	33	0	0	0	24	17	0	-	10	-	22	7	20	94	127
TOTAL mmbbl	135	287	388	39	44	71	3	17	26	42	30	5	5	52	63	85	100	245	438	709

Source: Bank mission estimates.
M.L. - Most Likely

THAILAND
FUEL OPTION STUDY

Table A5.3 - Offshore Gas Production Forecast
(mmcfd)

	Unocal I-II-III			Bongkot			Unocal 12/27			Maersk	JDA	Total Offshore		
Year	Firm	M.L.	High	Firm	M.L.	High	Firm	M.L.	High	High	High	Firm	M.L.	High
1993	775	775	775	75	75	75		-	-	-	-	850	850	850
1994	750	750	800	200	200	150		-	-	-	-	950	950	950
1995	650	650	700	300	300	250		-	-	-	-	950	950	950
1996	600	750	900	350	350	350		-	-	-	-	950	1100	1250
1997	570	750	900	350	350	350		-	-	-	-	950	1100	1250
1998	570	775	900	350	350	350	30	75	100	50	-	950	1200	1400
1999	570	775	1000	350	400	400	30	125	150	100	-	950	1300	1650
2000	570	825	1050	350	400	500	30	125	150	100	150	950	1350	1950
2001	570	825	1000	350	400	500	30	125	200	100	200	950	1350	2000
2002	570	800	1000	350	400	500	30	150	200	150	250	950	1350	2100
2003	570	800	1000	350	400	500	30	150	200	150	300	950	1350	2150
2004	570	800	1000	350	400	500	30	150	200	150	300	950	1350	2150
2005	570	825	1000	350	400	500	30	125	200	150	300	950	1350	2150
2006	430	825	940	350	400	500	30	125	200	150	300	810	1350	2090
2007	320	715	780	350	400	500	30	125	200	150	300	700	1190	1930
2008	230	610	660	350	350	500	30	100	200	150	300	610	1060	1810
2009	160	490	570	350	280	500	30	80	150	150	300	540	850	1670
2010	100	385	430	350	225	500	30	75	120	150	300	480	685	1500
TOTAL (bcf) 1993-2010	3338	4791	5623	2126	2219	2710	142	558	829	621	1095	5606	7568	10877
After 2010	172	2360	3957	44	263	1230	13	2	0	80	405	229	2625	5672
TOTAL (bcf)	3510	7151	9580	2170	2482	3940	155	560	829	701	1500	5835	10193	16549

Source: Bank mission estimates.
M.L. - Most Likely

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FUEL OPTION STUDY

Table A5.4 - Total Domestic Gas Production Forecast
(mmcfd)

	Shell S-1			Namphong			Total Onshore			Total Offshore			Total Domestic		
Year	Firm	M.L.	High	Firm	M.L.	High	Firm	M.L.	High	Firm	M.L.	High	Firm	M.L.	High
1993	47	47	47	60	60	60	107	107	107	850	850	850	957	957	957
1994	47	47	47	60	60	60	107	107	107	950	950	950	1057	1057	1057
1995	47	47	47	60	60	60	107	107	107	950	950	950	1057	1057	1057
1996	47	47	47	60	60	60	107	107	107	950	1100	1250	1057	1207	1357
1997	47	47	47	60	60	60	107	107	107	950	1100	1250	1057	1207	1357
1998	47	47	47	60	60	60	107	107	107	950	1200	1400	1057	1307	1507
1999	43	43	43	60	60	60	103	103	103	950	1300	1650	1053	1403	1753
2000	38	38	38	60	60	60	98	98	98	950	1350	1950	1048	1448	2048
2001	34	34	34	60	60	60	94	94	94	950	1350	2000	1044	1444	2094
2002	30	30	30	60	60	60	90	90	90	950	1350	2100	1040	1440	2190
2003	26	26	31	52	52	57	78	78	88	950	1350	2150	1028	1428	2238
2004	23	23	28	44	44	57	67	67	85	950	1350	2150	1017	1417	2235
2005	20	20	28	38	38	51	58	58	79	950	1350	2150	1008	1408	2229
2006	17	17	27	33	33	50	50	50	77	810	1350	2090	860	1400	2167
2007	16	16	27	28	28	49	44	44	76	700	1190	1930	744	1234	2006
2008	14	14	26	24	24	46	38	38	72	610	1060	1810	648	1098	1882
2009	12	12	25	21	21	43	33	33	68	540	850	1670	573	883	1738
2010	11	11	25	18	18	43	29	29	68	480	685	1500	509	714	1568
TOTAL (bcf) 1993-2010	207	207	235	313	313	363	520	520	598	5606	7568	10877	6126	8088	11476
After 2010	53	91	88	47	159	183	100	250	271	229	2625	5672	329	2875	5943
TOTAL (bcf)	260	298	323	360	472	546	620	770	869	5835	10193	16549	6455	10963	17419

Source: Bank mission estimates.
M.L. - Most Likely

THAILAND
FUEL OPTION STUDY

Table A5.5 - Total Gas Availability - Domestic and Imports
(mmcfd)

	Malaysia		Myanmar		Total Domestic			Total Availability		
Year	M.L.	High	M.L.	High	Firm	M.L.	High	Firm	M.L.	High
1993	-	-	-	-	957	957	957	957	957	957
1994	-	-	-	-	1057	1057	1057	1057	1057	1057
1995	-	-	-	-	1057	1057	1057	1057	1057	1057
1996	-	-	-	-	1057	1207	1357	1057	1207	1357
1997	-	-	-	-	1057	1207	1357	1057	1207	1357
1998	-	-	300	300	1057	1307	1507	1057	1607	1807
1999	-	-	300	300	1053	1403	1753	1053	1703	2053
2000	-	-	300	300	1048	1448	2048	1048	1748	2348
2001	-	150	300	300	1044	1444	2094	1044	1744	2544
2002	-	150	300	300	1040	1440	2190	1040	1740	2640
2003	-	150	300	300	1028	1428	2238	1028	1728	2688
2004	-	150	300	300	1017	1417	2235	1017	1717	2685
2005	-	150	300	500	1008	1408	2229	1008	1708	2879
2006	-	150	300	500	860	1400	2167	860	1700	2817
2007	-	150	300	500	744	1234	2006	744	1534	2656
2008	-	150	300	500	648	1098	1882	648	1398	2532
2009	-	150	300	500	573	883	1738	573	1183	2388
2010	-	150	300	500	509	714	1568	509	1014	2218
TOTAL (bcf)	-	548	1424	1862	6126	8088	11476	6126	9512	13885

Source: Bank mission estimates.
M.L. - Most Likely

THAILAND
FUEL OPTION STUDY

AVERAGE COST OF DOMESTIC & IMPORTED GAS
Table A6.1: Unocal Gas Production Cost
(Constant 1992 US Dollars)

Year	Capital Cost ($mil)	Oper. Cost ($mil)	Total Cost ($mil)	Gas Daily Flow 1/ (mmcfd)	Gas Annual Flow (BCF)	Condensate Annual Flow (mmbbl)	Unit Value 2/ Condensate ($/bbl)	Total Condensate Benefit ($mil)	Net Gas Cost ($mil)
1993	148.00	43.80	191.80	0	0	0	0	0	191.80
1994	202.00	54.75	256.75	0	0	0	0	0	256.75
1995	260.00	65.00	325.00	0	0	0	0	0	325.00
1996	215.00	65.00	280.00	200.00	73.00	1.00	14.27	14.27	265.74
1997	205.00	65.00	270.00	250.00	91.25	1.25	14.72	18.41	251.60
1998	100.00	65.00	165.00	400.00	146.00	1.50	15.51	23.26	141.74
1999	70.00	65.00	135.00	450.00	164.25	2.00	16.29	32.58	102.42
2000	50.00	65.00	115.00	500.00	182.50	2.50	17.13	42.82	72.18
2001	50.00	65.00	115.00	500.00	182.50	2.50	18.02	45.05	69.96
2002	50.00	65.00	115.00	500.00	182.50	2.50	18.95	47.36	67.64
2003	40.00	65.00	105.00	500.00	182.50	2.50	18.71	46.78	58.22
2004	40.00	65.00	105.00	500.00	182.50	2.50	18.55	46.37	58.63
2005	40.00	65.00	105.00	500.00	182.50	2.50	18.30	45.74	59.26
2006	30.00	65.00	95.00	500.00	182.50	2.50	18.09	45.23	49.77
2007	30.00	65.00	95.00	500.00	182.50	2.50	17.94	44.84	50.16
2008	20.00	65.00	85.00	500.00	182.50	2.50	17.92	44.80	40.20
2009	20.00	65.00	85.00	500.00	182.50	2.50	17.93	44.82	40.18
2010	15.00	65.00	80.00	500.00	182.50	2.50	17.92	44.80	35.20
2011	0	65.00	65.00	500.00	182.50	2.50	17.93	44.82	20.18
2012	0	65.00	65.00	500.00	182.50	2.50	17.90	44.75	20.25
2013	0	65.00	65.00	450.00	164.25	2.00	17.90	35.80	29.20
2014	0	65.00	65.00	450.00	164.25	2.00	17.90	35.80	29.20
2015	0	65.00	65.00	450.00	164.25	2.00	17.90	35.80	29.20
NPV @10%	991.58	549.67	1541.25	2737.46	999.17	13.18	108.64	229.31	1311.94

1/ Incremental production.
2/ Based on Bank projection of crude oil price, adjusted for quality and shipment cost of condensate.

Net unit cost = US$1.31/mcf

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

AVERAGE COST OF DOMESTIC & IMPORTED GAS
Table A6.2: Bongkot Gas Production Cost
(Constant 1992 US Dollars)

Year	Capital Cost ($mil)	Oper. Cost ($mil)	Total Cost ($mil)	Gas Annual Flow 1/ (BCF)	Condensate Annual Flow (mmbbl)	Unit Value Condensate 2/ ($/bbl)	Benefit Condensate ($mil)	Net Gas Cost ($mil)
1992	141.79	15.73	157.52	0	0	0	0	157.52
1993	213.29	34.98	248.27	0	0	0	0	248.27
1994	122.76	56.21	178.97	0	0	0	0	178.97
1995	37.84	54.67	92.51	64.00	1.00	14.27	14.27	78.25
1996	94.82	57.75	152.57	82.50	1.25	14.72	18.41	134.17
1997	52.25	57.86	110.11	96.10	1.25	15.51	19.38	90.73
1998	14.08	62.15	76.23	109.50	1.50	16.29	24.44	51.80
1999	104.06	62.15	166.21	91.25	1.50	17.13	25.69	140.52
2000	59.18	63.80	122.98	91.25	1.75	18.02	31.53	91.45
2001	12.98	63.80	76.78	91.25	1.75	18.95	33.15	43.63
2002	69.08	63.80	132.88	91.25	1.75	18.71	32.74	100.14
2003	44.11	63.80	107.91	91.25	1.75	18.55	32.46	75.45
2004	5.83	63.80	69.63	91.25	1.75	18.30	32.02	37.61
2005	33.77	63.25	97.02	91.25	1.75	18.09	31.66	65.36
2006	41.91	63.25	105.16	91.25	1.75	17.94	31.39	73.77
2007	0	63.25	63.25	91.25	1.75	17.92	31.36	31.89
2008	0	56.65	56.65	91.25	1.50	17.93	26.89	29.76
2009	0	47.85	47.85	91.25	1.00	17.92	17.92	29.93
2010	0	35.75	35.75	91.25	0.50	17.93	8.96	26.79
2011	0	22.00	22.00	91.25	0.50	17.90	8.95	13.05
2012	0	22.00	22.00	91.25	0.50	17.90	8.95	13.05
2013	0	22.00	22.00	91.25	0.50	17.90	8.95	13.05
2014	0	22.00	22.00	91.25	0.50	17.90	8.95	13.05
NPV @10%	656.37	447.64	1104.01	571.73	8.81	108.64	151.21	952.80

1/ Based on contractual quantity.
2/ Based on Bank projection of crude oil price, adjusted for quality and shipment cost of condensate.

Net unit cost = US$1.67/mcf

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

AVERAGE COST OF DOMESTIC & IMPORTED GAS
Table A6.3: Bongkot-Erawan Gas Transmission Cost
(Constant 1992 US Dollars)

Year	Capital Cost ($mil)	Oper. Cost ($mil)	Total Cost ($mil)	Scen 1 Flow 1/ bcf/yr
1992	48.00	0	48.00	0
1993	108.00	0	108.00	0
1994	44.00	0	44.00	0
1995	0	6.00	6.00	64.00
1996	0	6.00	6.00	82.50
1997	0	6.00	6.00	96.10
1998	0	6.00	6.00	109.50
1999	0	6.00	6.00	91.25
2000	0	6.00	6.00	91.25
2001	0	6.00	6.00	91.25
2002	0	6.00	6.00	91.25
2003	0	6.00	6.00	91.25
2004	0	6.00	6.00	91.25
2005	0	6.00	6.00	91.25
2006	0	6.00	6.00	91.25
2007	0	6.00	6.00	91.25
2008	0	6.00	6.00	91.25
2009	0	6.00	6.00	91.25
2010	0	6.00	6.00	91.25
2011	0	6.00	6.00	91.25
2012	0	6.00	6.00	91.25
2013	0	6.00	6.00	91.25
2014	0	6.00	6.00	91.25
NPV @10%	165.95	38.38	204.33	571.73

1/ Based on contractual quantity.

Unit transmission cost = US$0.36/mcf

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

AVERAGE COST OF DOMESTIC & IMPORTED GAS
Table A6.4: Erawan-Rayong Gas Transmission Cost
(Constant 1992 US Dollars)

Year	Capital Cost ($mil)	Oper. Cost ($mil)	Total Cost ($mil)	Scen 1 Daily Flow mmcfd	Scen 2 Daily Flow mmcfd	Scen 3 Daily Flow mmcfd	Scen 1 Annual Flow 1/ bcf/yr	Scen 2 Annual Flow 1/ bcf/yr	Scen 3 Annual Flow 1/ bcf/yr
1993	40.80	0	40.8	0	0	0	0	0	0
1994	270.80	0	270.8	0	0	0	0	0	0
1995	184.80	0	184.8	0	0	0	0	0	0
1996	28.80	17.00	45.80	200.00	200.00	200.00	73.00	73.00	73.00
1997	45.30	17.00	62.30	250.00	250.00	250.00	91.25	91.25	91.25
1998	0	17.00	17.00	400.00	400.00	400.00	146.00	146.00	146.00
1999	0	17.00	17.00	450.00	450.00	450.00	164.25	164.25	164.25
2000	0	17.00	17.00	500.00	700.00	700.00	182.50	255.50	255.50
2001	0	17.00	17.00	500.00	700.00	700.00	182.50	255.50	255.50
2002	0	17.00	17.00	500.00	700.00	700.00	182.50	255.50	255.50
2003	0	17.00	17.00	500.00	700.00	700.00	182.50	255.50	255.50
2004	0	17.00	17.00	500.00	700.00	700.00	182.50	255.50	255.50
2005	0	17.00	17.00	500.00	700.00	700.00	182.50	255.50	255.50
2006	0	17.00	17.00	500.00	650.00	700.00	182.50	237.25	255.50
2007	0	17.00	17.00	500.00	650.00	800.00	182.50	237.25	292.00
2008	0	17.00	17.00	500.00	650.00	800.00	182.50	237.25	292.00
2009	0	17.00	17.00	500.00	650.00	800.00	182.50	237.25	292.00
2010	0	17.00	17.00	500.00	650.00	800.00	182.50	237.25	292.00
2011	0	17.00	17.00	500.00	650.00	800.00	182.50	237.25	292.00
2012	0	17.00	17.00	500.00	650.00	800.00	182.50	237.25	292.00
2013	0	17.00	17.00	450.00	650.00	800.00	164.25	237.25	292.00
2014	0	17.00	17.00	450.00	650.00	800.00	164.25	237.25	292.00
2015	0	17.00	17.00	450.00	650.00	800.00	164.25	237.25	292.00
NPV @10%	447.53	108.74	556.27	2737.46	3469.91	3710.56	999.17	1266.52	1354.35

1/ The three scenarios are based on various flow options, including increased flow from Bongkot, gas imports from Malaysia, and increased production from Unocal.

Unit transmission cost Scenario 1 = US$0.56/mcf
Unit transmission cost Scenario 2 = US$0.44/mcf
Unit transmission cost Scenario 3 = US$0.41/mcf

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

AVERAGE COST OF DOMESTIC & IMPORTED GAS
Table A6.5: Erawan-Khanom Gas Transmission Cost
(Constant 1992 US Dollars)

Year	Capital Cost ($mil)	Oper. Cost ($mil)	Total Cost ($mil)	Scen 1 Annual Flow 1/ bcf/yr	Scen 2 Annual Flow 2/ bcf/yr	Scen 3 Annual Flow 2/ bcf/yr
1992	32.00	0	32.00	0	0	0
1993	73.00	0	73.00	0	0	0
1994	30.00	0	30.00	0	0	0
1995	0	4.00	4.00	36.50	36.50	36.50
1996	0	4.00	4.00	36.50	36.50	36.50
1997	0	4.00	4.00	36.50	36.50	36.50
1998	0	4.00	4.00	36.50	36.50	36.50
1999	0	4.00	4.00	36.50	36.50	36.50
2000	0	4.00	4.00	36.50	73.00	73.00
2001	0	4.00	4.00	36.50	73.00	73.00
2002	0	4.00	4.00	36.50	73.00	73.00
2003	0	4.00	4.00	36.50	73.00	73.00
2004	0	4.00	4.00	36.50	73.00	73.00
2005	0	4.00	4.00	36.50	73.00	127.70
2006	0	4.00	4.00	36.50	73.00	127.70
2007	0	4.00	4.00	36.50	73.00	127.70
2008	0	4.00	4.00	36.50	73.00	127.70
2009	0	4.00	4.00	36.50	73.00	127.70
2010	0	4.00	4.00	36.50	73.00	127.70
2011	0	4.00	4.00	36.50	73.00	127.70
2012	0	4.00	4.00	36.50	73.00	127.70
2013	0	4.00	4.00	36.50	73.00	127.70
2014	0	4.00	4.00	36.50	73.00	127.70
NPV @10%	111.96	25.59	137.55	233.47	362.98	460.34

1/ Scenario 1 is based on 100 mmcfd gas flow from Erawan to Khanom.
2/ Scenarios 2 and 3 are based on gas imported from Malaysia, flowing in reverse direction from Khanom to Erawan.

Unit gas transmission cost Scenario 1 = US$0.59/mcf
Unit gas transmission cost Scenario 2 = US$0.38/mcf
Unit gas transmission cost Scenario 3 = US$0.30/mcf

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

AVERAGE COST OF DOMESTIC & IMPORTED GAS
Table A6.6: Rayong-Bangkok Gas Transmission Cost
(Constant 1992 US Dollars)

Year	Capital Cost ($mil)	Oper. Cost ($mil)	Total Cost ($mil)	Scen 1 Annual Flow 1/ bcf/yr	Scen 2 Annual Flow 2/ bcf/yr	Scen 3 Annual Flow 3/ bcf/yr
1994	8.00	0	8.00	0	0	0
1995	32.00	0	32.00	0	0	0
1996	52.00	0	52.00	54.75	54.75	54.75
1997	28.00	0	28.00	73.00	73.00	73.00
1998	0	3.60	3.60	109.50	109.50	109.50
1999	0	3.60	3.60	109.50	109.50	109.50
2000	0	3.60	3.60	127.75	200.75	200.75
2001	0	3.60	3.60	127.75	200.75	200.75
2002	0	3.60	3.60	127.75	200.75	200.75
2003	0	3.60	3.60	127.75	200.75	200.75
2004	0	3.60	3.60	127.75	200.75	200.75
2005	0	3.60	3.60	127.75	200.75	200.75
2006	0	3.60	3.60	127.75	200.75	255.50
2007	0	3.60	3.60	127.75	200.75	255.50
2008	0	3.60	3.60	127.75	200.75	255.50
2009	0	3.60	3.60	127.75	200.75	255.50
2010	0	3.60	3.60	127.75	200.75	255.50
2011	0	3.60	3.60	127.75	200.75	255.50
2012	0	3.60	3.60	127.75	200.75	255.50
2013	0	3.60	3.60	109.50	182.50	237.25
2014	0	3.60	3.60	109.50	182.50	237.25
2015	0	3.60	3.60	109.50	182.50	237.25
NPV @10%	91.91	20.17	112.08	777.55	1099.94	1207.13

1/ Scenario 1 is based on 150, 200, 300 and 350 mmcfd, depending on various flow schemes from Erawan.
2/ Scenario 2 is based on 150, 200, 300, 500 and 550 mmcfd, depending on various flow schemes from Erawan.
3/ Scenario 3 is based on 150, 200, 300, 550, 650 and 700 mmcfd, depending on various flow schemes from Erawan.

Unit gas transmission cost Scenario 1 = US$0.14/mcf
Unit gas transmission cost Scenario 2 = US$0.11/mcf
Unit gas transmission cost Scenario 3 = US$0.09/mcf

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

AVERAGE COST OF DOMESTIC & IMPORTED GAS
Table A6.7: Khanom-Bangkok Gas Transmission Cost
(Constant 1992 US Dollars)

Year	Capital Cost ($mil)	Oper. Cost ($mil)	Total Cost ($mil)	Scen 1 Annual Flow 1/ bcf/yr	Scen 2 Annual Flow 2/ bcf/yr
1995	50.00	0	50.00	0	0
1996	250.00	0	250.00	0	0
1997	250.00	0	250.00	0	0
1998	100.00	0	100.00	0	0
1999	0	20.00	20.00	73.00	73.00
2000	0	20.00	20.00	73.00	73.00
2001	0	20.00	20.00	73.00	73.00
2002	0	20.00	20.00	73.00	73.00
2003	0	20.00	20.00	73.00	73.00
2004	0	20.00	20.00	73.00	127.75
2005	0	20.00	20.00	73.00	127.75
2006	0	20.00	20.00	73.00	127.75
2007	0	20.00	20.00	73.00	127.75
2008	0	20.00	20.00	73.00	127.75
2009	0	20.00	20.00	73.00	127.75
2010	0	20.00	20.00	73.00	127.75
2011	0	20.00	20.00	73.00	127.75
2012	0	20.00	20.00	73.00	127.75
2013	0	20.00	20.00	73.00	127.75
2014	0	20.00	20.00	73.00	127.75
2015	0	20.00	20.00	73.00	127.75
2016	0	20.00	20.00	73.00	127.75
2017	0	20.00	20.00	73.00	127.75
2018	0	20.00	20.00	73.00	127.75
NPV @10%	508.20	116.30	624.49	424.49	601.09

1/ Scenario 1 is based on surplus Malaysia gas from Khanom to Bangkok via onshore pipeline @200 mmcfd.
2/ Scenario 2 is the same as Scenario 1, except its flow increases to 350 mmcfd after 2004.

Unit gas transmission cost Scenario 1 = US$1.47/mcf
Unit gas transmission cost Scenario 2 = US$1.04/mcf

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

AVERAGE COST OF DOMESTIC & IMPORTED GAS
Table A6.8: Martaban (Myanmar) - Thai/Myanmar Border
(Constant 1992 US Dollars)

Year	Production Cost ($mil)	Production Oper. Cost ($mil)	Total Production Cost ($mil)	Scenario 1 Flow 1/ bcf/yr	Scenario 2 Flow 2/ bcf/yr	Transmission Capital Cost ($mil)	Transmission Oper. Cost ($mil)	Total Transmission Cost ($mil)
1994	50.00	0	50.00	0	0	0	0	0
1995	100.00	0	100.00	0	0	100.00	0	100.00
1996	100.00	0	100.00	0	0	200.00	0	200.00
1997	100.00	0	100.00	0	0	200.00	0	200.00
1998	0	50.00	50.00	109.50	109.50	0	15.00	15.00
1999	0	50.00	50.00	109.50	109.50	0	15.00	15.00
2000	0	50.00	50.00	109.50	109.50	0	15.00	15.00
2001	0	50.00	50.00	109.50	109.50	0	15.00	15.00
2002	0	50.00	50.00	109.50	109.50	0	15.00	15.00
2003	0	50.00	50.00	109.50	109.50	0	15.00	15.00
2004	100.00	50.00	150.00	109.50	109.50	0	15.00	15.00
2005	0	50.00	50.00	109.50	182.50	0	15.00	15.00
2006	0	50.00	50.00	109.50	182.50	0	15.00	15.00
2007	0	50.00	50.00	109.50	182.50	0	15.00	15.00
2008	0	50.00	50.00	109.50	182.50	0	15.00	15.00
2009	0	50.00	50.00	109.50	182.50	0	15.00	15.00
2010	100.00	50.00	150.00	109.50	182.50	0	15.00	15.00
2011	0	50.00	50.00	109.50	182.50	0	15.00	15.00
2012	0	50.00	50.00	109.50	182.50	0	15.00	15.00
2013	0	50.00	50.00	109.50	182.50	0	15.00	15.00
2014	0	50.00	50.00	109.50	182.50	0	15.00	15.00
2015	0	50.00	50.00	109.50	182.50	0	15.00	15.00
2016	0	50.00	50.00	109.50	182.50	0	15.00	15.00
2017	0	50.00	50.00	109.50	182.50	0	15.00	15.00
NPV @10%	326.37	290.74	617.11	636.73	818.48	369.51	87.22	456.73

1/ Scenario 1 is based on 300 mcfd.
2/ Scenario 2 is based on 300 mmcfd and increases to 500 mmcfd after 2005.

Unit production cost for Scenario 1 = US$0.97/mmcfd
Unit transmission cost for Scenario 1 = US$0.72/mmcfd
Total unit cost to Thai border for Scenario 1 = US$1.69/mmcfd

Unit production cost for Scenario 2 = US$0.75/mmcfd
Unit transmission cost for Scenario 2 = US$0.56/mmcfd
Total unit cost to Thai border for Scenario 2 = US$1.31/mmcfd

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

AVERAGE COST OF DOMESTIC & IMPORTED GAS
Table A6.9: Thai/Myanmar Border - Bangkok Cost
(Constant 1992 US Dollars)

Year	Capital Cost ($mil)	Oper. Cost ($mil)	Total Cost ($mil)	Scenario 1 Annual Flow 1/ bcf/yr	Scenario 2 Annual Flow 2/ bcf/yr
1995	100.00	0	100.00	0	0
1996	200.00	0	200.00	0	0
1997	100.00	0	100.00	0	0
1998	0	10.50	10.50	109.50	109.50
1999	0	10.50	10.50	109.50	109.50
2000	0	10.50	10.50	109.50	109.50
2001	0	10.50	10.50	109.50	109.50
2002	0	10.50	10.50	109.50	109.50
2003	0	10.50	10.50	109.50	109.50
2004	0	10.50	10.50	109.50	109.50
2005	0	10.50	10.50	109.50	182.50
2006	0	10.50	10.50	109.50	182.50
2007	0	10.50	10.50	109.50	182.50
2008	0	10.50	10.50	109.50	182.50
2009	0	10.50	10.50	109.50	182.50
2010	0	10.50	10.50	109.50	182.50
2011	0	10.50	10.50	109.50	182.50
2012	0	10.50	10.50	109.50	182.50
2013	0	10.50	10.50	109.50	182.50
2014	0	10.50	10.50	109.50	182.50
2015	0	10.50	10.50	109.50	182.50
2016	0	10.50	10.50	109.50	182.50
2017	0	10.50	10.50	109.50	182.50
NPV @10%	331.33	67.16	398.49	700.40	900.32

1/ Scenario 1 is based on 300 mmcfd.
2/ Scenario 2 is based on 300 mmcfd, and increases to 500 mmcfd after 2005.

Unit transmission cost for Scenario 1 = US$0.57 mmcfd
Unit transmission cost for Scenario 2 = US$0.44 mmcfd

Total unit gas cost from Myanmar gas fields to Bangkok for Scenario 1 = US$2.26/mmcfd
Total unit gas cost from Myanmar gas fields to Bangkok for Scenario 2 = US$1.75/mmcfd

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

AVERAGE COST OF DOMESTIC & IMPORTED GAS
Table A6.10: Kerteh - Malaysia Thailand Border
(Constant 1992 US Dollars)

Year	Unit Production Cost 1/ $/mcf	Scenario 1 Annual Flow 2/ bcf/yr	Scenario 2 Annual Flow 3/ bcf/yr	Scenario 1 Total Prod Costs 2/ ($mil)	Scenario 2 Total Prod Costs 3/ ($mil)	Transmission Capital Cost ($mil)	Transmission Oper. Cost ($mil)	Total Transmission Cost ($mil)
1995	0.79	0	0	0	0	0	0	0
1996	0.81	0	0	0	0	0	0	0
1997	0.83	0	0	0	0	50.00	0	50.00
1998	0.84	0	0	0	0	100.00	0	100.00
1999	0.86	0	0	0	0	50.00	0	50.00
2000	0.88	109.50	109.50	96.45	96.45	0	6.00	6.00
2001	0.90	109.50	109.50	98.57	98.57	0	6.00	6.00
2002	0.92	109.50	109.50	100.74	100.74	0	6.00	6.00
2003	0.94	109.50	109.50	102.96	102.96	0	6.00	6.00
2004	0.96	109.50	109.50	105.22	105.22	0	6.00	6.00
2005	0.98	109.50	109.50	107.54	107.54	0	6.00	6.00
2006	1.00	109.50	219.00	109.90	219.80	0	6.00	6.00
2007	1.03	109.50	219.00	112.32	224.64	0	6.00	6.00
2008	1.05	109.50	219.00	114.79	229.58	0	6.00	6.00
2009	1.07	109.50	219.00	117.32	234.63	0	6.00	6.00
2010	1.09	109.50	219.00	119.90	239.79	0	6.00	6.00
2011	1.12	109.50	219.00	122.53	245.07	0	6.00	6.00
2012	1.14	109.50	219.00	125.23	250.46	0	6.00	6.00
2013	1.17	109.50	219.00	127.98	255.97	0	6.00	6.00
2014	1.19	109.50	219.00	130.80	261.60	0	6.00	6.00
2015	1.22	109.50	219.00	133.68	267.36	0	6.00	6.00
2016	1.25	109.50	219.00	136.62	273.24	0	6.00	6.00
2017	1.28	109.50	219.00	139.62	279.25	0	6.00	6.00
2018	1.30	109.50	219.00	142.70	285.39	0	6.00	6.00
2019	1.33	109.50	219.00	145.84	291.67	0	6.00	6.00
NPV @10%		578.84	861.57	591.42	908.90	136.91	31.72	168.63

1/ Costs do not include depletion premium, but include credit for condensate.
2/ Scenario 1 is based on 300 mmcfd
3/ Scenario 2 is based on 300 mmcfd, and increases to 600 mmcfd after 2006.

Unit production cost for Scenario 1 = US$1.02/mmcfd
Unit transmission cost for Scenario 1 = US$0.29/mmcfd
Total unit cost to Thai border for Scenario 1 = US$1.31/mmcfd

Unit production cost for Scenario 2 = US$1.05/mmcfd
Unit transmission cost for Scenario 2 = US$0.20/mmcfd
Total unit cost to Thai border for Scenario 2 = US$1.25/mmcfd

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

AVERAGE COST OF DOMESTIC & IMPORTED GAS
Table A6.11: Thai/Malaysia Border - Khanom Gas Transmission Cost
(Constant 1992 US Dollars)

Year	Capital Cost ($mil)	Oper. Cost ($mil)	Total Cost ($mil)	Scenario 1 Annual Flow 1/ bcf/yr	Scenario 2 Annual Flow 2/ bcf/yr	Scenario 3 Annual Flow 3/ bcf/yr
1996	50.00	0	50.00	0	0	0
1997	100.00	0	100.00	0	0	0
1998	150.00	0	150.00	0	0	0
1999	50.00	0	50.00	0	0	0
2000	0	10.50	10.50	54.75	109.50	109.50
2001	0	10.50	10.50	54.75	109.50	109.50
2002	0	10.50	10.50	54.75	109.50	109.50
2003	0	10.50	10.50	54.75	109.50	109.50
2004	0	10.50	10.50	54.75	109.50	109.50
2005	0	10.50	10.50	54.75	109.50	109.50
2006	0	10.50	10.50	54.75	109.50	219.00
2007	0	10.50	10.50	54.75	109.50	219.00
2008	0	10.50	10.50	54.75	109.50	219.00
2009	0	10.50	10.50	54.75	109.50	219.00
2010	0	10.50	10.50	54.75	109.50	219.00
2011	0	10.50	10.50	54.75	109.50	219.00
2012	0	10.50	10.50	54.75	109.50	219.00
2013	0	10.50	10.50	54.75	109.50	219.00
2014	0	10.50	10.50	54.75	109.50	219.00
2015	0	10.50	10.50	54.75	109.50	219.00
2016	0	10.50	10.50	54.75	109.50	219.00
2017	0	10.50	10.50	54.75	109.50	219.00
2018	0	10.50	10.50	54.75	109.50	219.00
2019	0	10.50	10.50	54.75	109.50	219.00
NPV @10%	274.95	61.06	336.00	318.36	636.73	947.73

1/ Scenario 1 is based on 150 mmcfd to Khanom.
2/ Scenario 2 is based on 300 mmcfd.
3/ Scenario 3 is based on 300 mmcfd, and an increase to 600 mmcfd after 2006.

Unit gas transmission cost Scenario 1 = US$1.06/mcf
Unit gas transmission cost Scenario 2 = US$0.53/mcf
Unit gas transmission cost Scenario 3 = US$0.35/mcf

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

POWER COST & NET BACK VALUE - GAS & LNG
Table A7.1: Combined Cycle Plant with Natural Gas
(Constant 1992 US Dollars)

ASSUMPTIONS:
Plant Factor - 70%
Efficiency - 44%
Size - 600 MW

Capital Cost - $650/kw
Operating Cost - 4.0% of investment cost

Life - 20 years
Construction Time - 3 years

Year	Capital Cost ($mil)	Power Generated (GWh/Year)	Gas Consumption (BCF/Year)	Unit Fuel Cost ($/mcf)	Total Fuel Cost ($mil)	Operating Cost ($mil)	Total Oper. Cost ($mil)	Total Capital & Oper. Cost ($mil)
1994	130.00	0	0	0	0	0	0	130.00
1995	130.00	0	0	0	0	0	0	130.00
1996	130.00	0	0	0	0	0	0	130.00
1997	0	1840.00	14.25	2.45	34.91	15.60	50.51	50.51
1998	0	2759.00	21.38	2.47	52.90	15.60	68.50	68.50
1999	0	3679.00	28.50	2.50	71.23	15.60	86.83	86.83
2000	0	3679.00	28.50	2.52	71.94	15.60	87.54	87.54
2001	0	3679.00	28.50	2.55	72.66	15.60	88.26	88.26
2002	0	3679.00	28.50	2.57	73.39	15.60	88.99	88.99
2003	0	3679.00	28.50	2.60	74.12	15.60	89.72	89.72
2004	0	3679.00	28.50	2.63	74.86	15.60	90.46	90.46
2005	0	3679.00	28.50	2.65	75.61	15.60	91.21	91.21
2006	0	3679.00	28.50	2.68	76.37	15.60	91.97	91.97
2007	0	3679.00	28.50	2.71	77.13	15.60	92.73	92.73
2008	0	3679.00	28.50	2.73	77.90	15.60	93.50	93.50
2009	0	3679.00	28.50	2.76	78.68	15.60	94.28	94.28
2010	0	3679.00	28.50	2.79	79.47	15.60	95.07	95.07
2011	0	3679.00	28.50	2.82	80.26	15.60	95.86	95.86
2012	0	3679.00	28.50	2.84	81.06	15.60	96.66	96.66
2013	0	3679.00	28.50	2.87	81.88	15.60	97.48	97.48
2014	0	3679.00	28.50	2.90	82.69	15.60	98.29	98.29
2015	0	3679.00	28.50	2.93	83.52	15.60	99.12	99.12
2016	0	3679.00	28.50	2.96	84.36	15.60	99.96	99.96
NPV @10%	323.29	21704.92	168.14		442.39	99.78	542.17	865.46

Power cost = US 3.99 cents/kWh

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

POWER COST & NET BACK VALUE - GAS & LNG
Table A7.2: Combined Cycle Plant with LNG
(Constant 1992 US Dollars)

ASSUMPTIONS:
Plant Factor - 70%
Efficiency - 44%
Size - 600 MW

Capital Cost - $650/kw
Operating Cost - 4.0% of investment cost

Life - 20 years
Construction Time - 3 years

Year	Capital Cost ($mil)	Power Generated (GWh/Year)	Gas Consumption (BCF/Year)	Unit Fuel Cost ($/mcf)	Total Fuel Cost ($mil)	Operating Cost ($mil)	Total Oper. Cost ($mil)	Total Capital & Oper. Cost ($mil)
1994	130.00	0	0	0	0	0	0	130.00
1995	130.00	0	0	0	0	0	0	130.00
1996	130.00	0	0	0	0	0	0	130.00
1997	0	1840.00	14.25	4.13	58.85	15.60	74.45	74.45
1998	0	2759.00	21.38	4.26	91.08	15.60	106.68	106.68
1999	0	3679.00	28.50	4.40	125.40	15.60	141.00	141.00
2000	0	3679.00	28.50	4.55	129.67	15.60	145.27	145.27
2001	0	3679.00	28.50	4.50	128.25	15.60	143.85	143.85
2002	0	3679.00	28.50	4.46	127.11	15.60	142.71	142.71
2003	0	3679.00	28.50	4.41	125.69	15.60	141.29	141.29
2004	0	3679.00	28.50	4.37	124.55	15.60	140.15	140.15
2005	0	3679.00	28.50	4.31	122.84	15.60	138.44	138.44
2006	0	3679.00	28.50	4.36	124.26	15.60	139.86	139.86
2007	0	3679.00	28.50	4.40	125.40	15.60	141.00	141.00
2008	0	3679.00	28.50	4.45	126.83	15.60	142.43	142.43
2009	0	3679.00	28.50	4.50	128.25	15.60	143.85	143.85
2010	0	3679.00	28.50	4.54	129.39	15.60	144.99	144.99
2011	0	3679.00	28.50	4.59	130.82	15.60	146.42	146.42
2012	0	3679.00	28.50	4.64	132.24	15.60	147.84	147.84
2013	0	3679.00	28.50	4.69	133.67	15.60	149.27	149.27
2014	0	3679.00	28.50	4.74	135.09	15.60	150.69	150.69
2015	0	3679.00	28.50	4.79	136.52	15.60	152.12	152.12
2016	0	3679.00	28.50	4.84	137.94	15.60	153.54	153.54
NPV @10%	323.29	21704.92	168.14		747.40	99.78	847.18	1170.47

Power cost = US 5.39 cents/kWh

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

POWER COST & NET BACK VALUE - COAL, FUEL OIL & LIGNITE
Table A8.1: Coal Fired Power Plant, Base Case
Low Sulphur Coal (0.5%), with low efficiency FGD
(Constant 1992 US Dollars)

ASSUMPTIONS:
Plant Factor - 70%
Efficiency - 36%
Size - 2000 MW
Capital Cost - $1190/kw
Operating Cost - 3.7% of investment cost
Life - 25 years
Construction Time - 5 years

Year	Capital Cost ($ mil)	Power Generated GWh/Year	Volume of Coal (mil tons)	Imp. Coal CIF ($/ton)	Fuel Cost ($ mil)	Operating Cost ($ mil)	Total Oper. Cost ($ mil)	Total Cost ($ mil)
1994	476.00	0	0	0	0	0	0	476.00
1995	476.00	0	0	0	0	0	0	476.00
1996	476.00	0	0	0	0	0	0	476.00
1997	476.00	0	0	0	0	0	0	476.00
1998	476.00	0	0	0	0	0	0	476.00
1999	0	6132.00	2.20	54.00	118.80	88.06	206.86	206.86
2000	0	9198.00	3.30	54.27	179.09	88.06	267.15	267.15
2001	0	12264.00	4.40	54.54	239.98	88.06	328.04	328.04
2002	0	12264.00	4.40	54.81	241.16	88.06	329.22	329.22
2003	0	12264.00	4.40	55.09	242.40	88.06	330.46	330.46
2004	0	12264.00	4.40	55.36	243.58	88.06	331.64	331.64
2005	0	12264.00	4.40	55.64	244.82	88.06	332.88	332.88
2006	0	12264.00	4.40	55.75	245.30	88.06	333.36	333.36
2007	0	12264.00	4.40	56.03	246.53	88.06	334.59	334.59
2008	0	12264.00	4.40	56.31	247.76	88.06	335.82	335.82
2009	0	12264.00	4.40	56.59	249.00	88.06	337.06	337.06
2010	0	12264.00	4.40	56.87	250.23	88.06	338.29	338.29
2011	0	12264.00	4.40	57.16	251.50	88.06	339.56	339.56
2012	0	12264.00	4.40	57.45	252.76	88.06	340.82	340.82
2013	0	12264.00	4.40	57.73	254.03	88.06	342.09	342.09
2014	0	12264.00	4.40	58.02	255.30	88.06	343.36	343.36
2015	0	12264.00	4.40	58.31	256.57	88.06	344.63	344.63
2016	0	12264.00	4.40	58.60	257.85	88.06	345.91	345.91
2017	0	12264.00	4.40	58.90	259.14	88.06	347.20	347.20
2018	0	12264.00	4.40	59.19	260.44	88.06	348.50	348.50
2019	0	12264.00	4.40	59.49	261.74	88.06	349.80	349.80
2020	0	12264.00	4.40	59.78	263.05	88.06	351.11	351.11
2021	0	12264.00	4.40	60.08	264.37	88.06	352.43	352.43
2022	0	12264.00	4.40	60.38	265.69	88.06	353.75	353.75
2023	0	12264.00	4.40	60.69	267.02	88.06	355.08	355.08
NPV @10%	1804.41	64086.77	22.99		1290.90	496.32	1787.22	3591.63

Power cost = US 5.60 cents/kWh

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

POWER COST & NET BACK VALUE - COAL, FUEL OIL & LIGNITE
Table A8.2: Coal Fired Power Plant, Alternative Case 1
Low Sulphur Coal (0.5%), with high efficiency FGD
(Constant 1992 US Dollars)

ASSUMPTIONS:
Plant Factor - 70%
Efficiency - 36%
Size - 2000 MW

Capital Cost - $1360/kw
Operating Cost - 3.7% of investment cost

Life - 25 years
Construction Time - 5 years

Year	Capital Cost ($ mil)	Power Generated GWh/Year	Volume of Coal (mil tons)	Imp. Coal CIF ($/ton)	Fuel Cost ($ mil)	Operating Cost ($ mil)	Total Oper. Cost ($ mil)	Total Cost ($ mil)
1994	544.00	0	0	0	0	0	0	544.00
1995	544.00	0	0	0	0	0	0	544.00
1996	544.00	0	0	0	0	0	0	544.00
1997	544.00	0	0	0	0	0	0	544.00
1998	544.00	0	0	0	0	0	0	544.00
1999	0	6132.00	2.20	54.00	118.80	100.64	219.44	219.44
2000	0	9198.00	3.30	54.27	179.09	100.64	279.73	279.73
2001	0	12264.00	4.40	54.54	239.98	100.64	340.62	340.62
2002	0	12264.00	4.40	54.81	241.16	100.64	341.80	341.80
2003	0	12264.00	4.40	55.09	242.40	100.64	343.04	343.04
2004	0	12264.00	4.40	55.36	243.58	100.64	344.22	344.22
2005	0	12264.00	4.40	55.64	244.82	100.64	345.46	345.46
2006	0	12264.00	4.40	55.75	245.30	100.64	345.94	345.94
2007	0	12264.00	4.40	56.03	246.53	100.64	347.17	347.17
2008	0	12264.00	4.40	56.31	247.76	100.64	348.40	348.40
2009	0	12264.00	4.40	56.59	249.00	100.64	349.64	349.64
2010	0	12264.00	4.40	56.87	250.23	100.64	350.87	350.87
2011	0	12264.00	4.40	57.16	251.50	100.64	352.14	352.14
2012	0	12264.00	4.40	57.45	252.76	100.64	353.40	353.40
2013	0	12264.00	4.40	57.73	254.03	100.64	354.67	354.67
2014	0	12264.00	4.40	58.02	255.30	100.64	355.94	355.94
2015	0	12264.00	4.40	58.31	256.57	100.64	357.21	357.21
2016	0	12264.00	4.40	58.60	257.85	100.64	358.49	358.49
2017	0	12264.00	4.40	58.90	259.14	100.64	359.78	359.78
2018	0	12264.00	4.40	59.19	260.44	100.64	361.08	361.08
2019	0	12264.00	4.40	59.49	261.74	100.64	362.38	362.38
2020	0	12264.00	4.40	59.78	263.05	100.64	363.69	363.69
2021	0	12264.00	4.40	60.08	264.37	100.64	365.01	365.01
2022	0	12264.00	4.40	60.38	265.69	100.64	366.33	366.33
2023	0	12264.00	4.40	60.69	267.02	100.64	367.66	367.66
NPV @10%	2062.19	64086.77	22.99		1290.90	567.22	1858.12	3920.31

Power cost = US 6.12 cents/kWh

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

POWER COST & NET BACK VALUE - COAL, FUEL OIL & LIGNITE
Table A8.3: Coal Fired Power Plant, Alternative Case 2
Low Sulphur Coal (0.5%), without FGD
(Constant 1992 US Dollars)

ASSUMPTIONS:
Plant Factor - 70%
Efficiency - 38%
Size - 2000 MW
Capital Cost - $1076/kw
Operating Cost - 3.7% of investment cost
Life - 25 years
Construction Time - 5 years

Year	Capital Cost ($ mil)	Power Generated GWh/Year	Volume of Coal (mil tons)	Imp. Coal CIF ($/ton)	Fuel Cost ($ mil)	Operating Cost ($ mil)	Total Oper. Cost ($ mil)	Total Cost ($ mil)
1994	430.40	0	0	0	0	0	0	430.40
1995	430.40	0	0	0	0	0	0	430.40
1996	430.40	0	0	0	0	0	0	430.40
1997	430.40	0	0	0	0	0	0	430.40
1998	430.40	0	0	0	0	0	0	430.40
1999	0	6132.00	2.09	54.00	112.86	79.62	192.48	192.48
2000	0	9198.00	3.13	54.27	169.87	79.62	249.49	249.49
2001	0	12264.00	4.17	54.54	227.43	79.62	307.05	307.05
2002	0	12264.00	4.17	54.81	228.56	79.62	308.18	308.18
2003	0	12264.00	4.17	55.09	229.73	79.62	309.35	309.35
2004	0	12264.00	4.17	55.36	230.85	79.62	310.47	310.47
2005	0	12264.00	4.17	55.64	232.02	79.62	311.64	311.64
2006	0	12264.00	4.17	55.75	232.48	79.62	312.10	312.10
2007	0	12264.00	4.17	56.03	233.65	79.62	313.27	313.27
2008	0	12264.00	4.17	56.31	234.81	79.62	314.43	314.43
2009	0	12264.00	4.17	56.59	235.98	79.62	315.60	315.60
2010	0	12264.00	4.17	56.87	237.15	79.62	316.77	316.77
2011	0	12264.00	4.17	57.16	238.36	79.62	317.98	317.98
2012	0	12264.00	4.17	57.45	239.55	79.62	319.17	319.17
2013	0	12264.00	4.17	57.73	240.75	79.62	320.37	320.37
2014	0	12264.00	4.17	58.02	241.95	79.62	321.57	321.57
2015	0	12264.00	4.17	58.31	243.16	79.62	322.78	322.78
2016	0	12264.00	4.17	58.60	244.38	79.62	324.00	324.00
2017	0	12264.00	4.17	58.90	245.60	79.62	325.22	325.22
2018	0	12264.00	4.17	59.19	246.83	79.62	326.45	326.45
2019	0	12264.00	4.17	59.49	248.06	79.62	327.68	327.68
2020	0	12264.00	4.17	59.78	249.30	79.62	328.92	328.92
2021	0	12264.00	4.17	60.08	250.55	79.62	330.17	330.17
2022	0	12264.00	4.17	60.38	251.80	79.62	331.42	331.42
2023	0	12264.00	4.17	60.69	253.06	79.62	332.68	332.68
NPV @10%	1631.55	64086.77	21.79		1223.64	448.75	1672.39	3303.95

Power cost = US 5.16 cents/kWh

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

POWER COST & NET BACK VALUE - COAL, FUEL OIL & LIGNITE
Table A8.4: Fuel Oil Fired Power Plant, Base Case
Low Sulphur Fuel Oil (0.5%), without FGD
(Constant 1992 US Dollars)

ASSUMPTIONS:
Plant Factor - 70%
Efficiency - 39%
Size - 2000 MW
Capital Cost - $900/kw
Operating Cost - 2.7% of investment cost
Life - 25 years
Construction Time - 4 years

Year	Capital Cost ($mil)	Power Generated GWh/Year	Volume of Fuel Oil (mmbbl)	Fuel Oil CIF ($/bbl)	Fuel Cost ($mil)	Operating Cost ($mil)	Total Oper. Cost ($mil)	Total Cost ($mil)
1994	450.00	0	0	0	0	0	0	450.00
1995	450.00	0	0	0	0	0	0	450.00
1996	450.00	0	0	0	0	0	0	450.00
1997	450.00	0	0	0	0	0	0	450.00
1998	0	6132.00	8.95	21.17	189.47	48.60	238.07	238.07
1999	0	9198.00	13.43	21.67	291.03	48.60	339.63	339.63
2000	0	12264.00	17.90	22.19	397.20	48.60	445.80	445.80
2001	0	12264.00	17.90	22.02	394.16	48.60	442.76	442.76
2002	0	12264.00	17.90	21.86	391.29	48.60	439.89	439.89
2003	0	12264.00	17.90	21.70	388.43	48.60	437.03	437.03
2004	0	12264.00	17.90	21.55	385.75	48.60	434.35	434.35
2005	0	12264.00	17.90	21.35	382.17	48.60	430.77	430.77
2006	0	12264.00	17.90	21.52	385.21	48.60	433.81	433.81
2007	0	12264.00	17.90	21.68	388.07	48.60	436.67	436.67
2008	0	12264.00	17.90	21.84	390.94	48.60	439.54	439.54
2009	0	12264.00	17.90	22.01	393.98	48.60	442.58	442.58
2010	0	12264.00	17.90	22.18	397.02	48.60	445.62	445.62
2011	0	12264.00	17.90	22.40	400.99	48.60	449.59	449.59
2012	0	12264.00	17.90	22.63	405.00	48.60	453.60	453.60
2013	0	12264.00	17.90	22.85	409.05	48.60	457.65	457.65
2014	0	12264.00	17.90	23.08	413.14	48.60	461.74	461.74
2015	0	12264.00	17.90	23.31	417.27	48.60	465.87	465.87
2016	0	12264.00	17.90	23.54	421.45	48.60	470.05	470.05
2017	0	12264.00	17.90	23.78	425.66	48.60	474.26	474.26
2018	0	12264.00	17.90	24.02	429.92	48.60	478.52	478.52
2019	0	12264.00	17.90	24.26	434.22	48.60	482.82	482.82
2020	0	12264.00	17.90	24.50	438.56	48.60	487.16	487.16
2021	0	12264.00	17.90	24.75	442.94	48.60	491.54	491.54
2022	0	12264.00	17.90	24.99	447.37	48.60	495.97	495.97
NPV @10%	1426.44	70495.45	102.89		2278.95	301.31	2580.26	4006.70

Power cost = US 5.68 cents/kWh

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

POWER COST & NET BACK VALUE - COAL, FUEL OIL & LIGNITE
Table A8.5: Fuel Oil Fired Power Plant, Alternative Case 1
Low Sulphur Fuel Oil (0.5%), with low efficiency FGD
(Constant 1992 US Dollars)

ASSUMPTIONS:
Plant Factor - 70%
Efficiency - 37%
Size: 2000 MW

Capital Cost - $1000/kw
Operating Cost - 2.7% of investment cost

Life - 25 years
Construction Time - 4 years

Year	Capital Cost ($mil)	Power Generated GWh/Year	Volume of Fuel Oil (mmbbl)	Fuel Oil CIF ($/bbl)	Fuel Cost ($mil)	Operating Cost ($mil)	Total Oper. Cost ($mil)	Total Cost ($mil)
1994	500.00	0	0	0	0	0	0	500.00
1995	500.00	0	0	0	0	0	0	500.00
1996	500.00	0	0	0	0	0	0	500.00
1997	500.00	0	0	0	0	0	0	500.00
1998	0	6132.00	9.44	21.17	199.84	54.00	253.84	253.84
1999	0	9198.00	14.15	21.67	306.63	54.00	360.63	360.63
2000	0	12264.00	18.87	22.19	418.73	54.00	472.73	472.73
2001	0	12264.00	18.87	22.02	415.52	54.00	469.52	469.52
2002	0	12264.00	18.87	21.86	412.50	54.00	466.50	466.50
2003	0	12264.00	18.87	21.70	409.48	54.00	463.48	463.48
2004	0	12264.00	18.87	21.55	406.65	54.00	460.65	460.65
2005	0	12264.00	18.87	21.35	402.87	54.00	456.87	456.87
2006	0	12264.00	18.87	21.52	406.08	54.00	460.08	460.08
2007	0	12264.00	18.87	21.68	409.10	54.00	463.10	463.10
2008	0	12264.00	18.87	21.84	412.12	54.00	466.12	466.12
2009	0	12264.00	18.87	22.01	415.33	54.00	469.33	469.33
2010	0	12264.00	18.87	22.18	418.54	54.00	472.54	472.54
2011	0	12264.00	18.87	22.40	422.72	54.00	476.72	476.72
2012	0	12264.00	18.87	22.63	426.95	54.00	480.95	480.95
2013	0	12264.00	18.87	22.85	431.22	54.00	485.22	485.22
2014	0	12264.00	18.87	23.08	435.53	54.00	489.53	489.53
2015	0	12264.00	18.87	23.31	439.89	54.00	493.89	493.89
2016	0	12264.00	18.87	23.54	444.29	54.00	498.29	498.29
2017	0	12264.00	18.87	23.78	448.73	54.00	502.73	502.73
2018	0	12264.00	18.87	24.02	453.22	54.00	507.22	507.22
2019	0	12264.00	18.87	24.26	457.75	54.00	511.75	511.75
2020	0	12264.00	18.87	24.50	462.32	54.00	516.32	516.32
2021	0	12264.00	18.87	24.75	466.95	54.00	520.95	520.95
2022	0	12264.00	18.87	24.99	471.62	54.00	525.62	525.62
NPV @10%	1584.93	70495.45	108.47		2402.42	334.79	2737.21	4322.14

Power cost = US 6.13 cents/kWh

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

POWER COST & NET BACK VALUE - COAL, FUEL OIL & LIGNITE
Table A8.6: Fuel Oil Fired Power Plant, Alternative 2 Case
High Sulphur Fuel Oil (3.0%), with high efficiency FGD
(Constant 1992 US Dollars)

ASSUMPTIONS:
Plant Factor - 70%
Efficiency - 37%
Size - 2000 MW
Capital Cost - $1150/kw
Operating Cost - 2.7% of investment cost
Life - 25 years
Construction Time - 4 years

Year	Capital Cost ($mil)	Power Generated GWh/Year	Volume of Fuel Oil (mmbbl)	Fuel Oil CIF ($/bbl)	Fuel Cost ($mil)	Operating Cost ($mil)	Total Oper. Cost ($mil)	Total Cost ($mil)
1994	575.00	0	0	0	0	0	0	575.00
1995	575.00	0	0	0	0	0	0	575.00
1996	575.00	0	0	0	0	0	0	575.00
1997	575.00	0	0	0	0	0	0	575.00
1998	0	6132.00	9.44	15.17	143.20	62.10	205.30	205.30
1999	0	9198.00	14.15	15.67	221.73	62.10	283.83	283.83
2000	0	12264.00	18.87	16.19	305.51	62.10	367.61	367.61
2001	0	12264.00	18.87	16.02	302.30	62.10	364.40	364.40
2002	0	12264.00	18.87	15.86	299.28	62.10	361.38	361.38
2003	0	12264.00	18.87	15.70	296.26	62.10	358.36	358.36
2004	0	12264.00	18.87	15.55	293.43	62.10	355.53	355.53
2005	0	12264.00	18.87	15.35	289.65	62.10	351.75	351.75
2006	0	12264.00	18.87	15.52	292.86	62.10	354.96	354.96
2007	0	12264.00	18.87	15.68	295.88	62.10	357.98	357.98
2008	0	12264.00	18.87	15.84	298.90	62.10	361.00	361.00
2009	0	12264.00	18.87	16.01	302.11	62.10	364.21	364.21
2010	0	12264.00	18.87	16.18	305.32	62.10	367.42	367.42
2011	0	12264.00	18.87	16.34	308.37	62.10	370.47	370.47
2012	0	12264.00	18.87	16.51	311.45	62.10	373.55	373.55
2013	0	12264.00	18.87	16.67	314.57	62.10	376.67	376.67
2014	0	12264.00	18.87	16.84	317.71	62.10	379.81	379.81
2015	0	12264.00	18.87	17.01	320.89	62.10	382.99	382.99
2016	0	12264.00	18.87	17.18	324.10	62.10	386.20	386.20
2017	0	12264.00	18.87	17.35	327.34	62.10	389.44	389.44
2018	0	12264.00	18.87	17.52	330.61	62.10	392.71	392.71
2019	0	12264.00	18.87	17.70	333.92	62.10	396.02	396.02
2020	0	12264.00	18.87	17.87	337.26	62.10	399.36	399.36
2021	0	12264.00	18.87	18.05	340.63	62.10	402.73	402.73
2022	0	12264.00	18.87	18.23	344.04	62.10	406.14	406.14
NPV @10%	1822.67	70495.45	108.47		1743.11	385.00	2128.11	3950.78

Power cost = US 5.60 cents/kWh

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

POWER COST & NET BACK VALUE - COAL, FUEL OIL & LIGNITE
Table A8.7: Lignite Fired Power Plant, Base Case
With high efficiency FGD
(Constant 1992 US Dollars)

ASSUMPTIONS:
Plant Factor - 70%
Efficiency - 33%
Size - 600 MW

Capital Cost - $1252/kw
Operating Cost - 4.0% of investment cost

Life - 25 years
Construction Time - 5 years

Year	Capital Cost ($ mil)	Power Generated GWh/Year	Volume of Lignite (mil tons)	Lignite CIF ($/ton)	Fuel Cost ($ mil)	Operating Cost ($ mil)	Total Oper. Cost ($ mil)	Total Cost ($ mil)
1994	150.24	0	0	0	0	0	0	150.24
1995	150.24	0	0	0	0	0	0	150.24
1996	150.24	0	0	0	0	0	0	150.24
1997	150.24	0	0	0	0	0	0	150.24
1998	150.24	0	0	0	0	0	0	150.24
1999	0	2759.00	2.40	14.52	34.85	30.05	64.90	64.90
2000	0	3311.00	2.87	14.65	42.05	30.05	72.10	72.10
2001	0	3679.00	3.19	14.78	47.15	30.05	77.20	77.20
2002	0	3679.00	3.19	14.92	47.59	30.05	77.64	77.64
2003	0	3679.00	3.19	15.05	48.01	30.05	78.06	78.06
2004	0	3679.00	3.19	15.19	48.46	30.05	78.51	78.51
2005	0	3679.00	3.19	15.32	48.87	30.05	78.92	78.92
2006	0	3679.00	3.19	15.51	49.48	30.05	79.53	79.53
2007	0	3679.00	3.19	15.76	50.27	30.05	80.32	80.32
2008	0	3679.00	3.19	16.01	51.07	30.05	81.12	81.12
2009	0	3679.00	3.19	16.27	51.90	30.05	81.95	81.95
2010	0	3679.00	3.19	16.53	52.73	30.05	82.78	82.78
2011	0	3679.00	3.19	16.29	51.97	30.05	82.02	82.02
2012	0	3679.00	3.19	16.53	52.74	30.05	82.79	82.79
2013	0	3679.00	3.19	16.78	53.54	30.05	83.59	83.59
2014	0	3679.00	3.19	17.03	54.34	30.05	84.39	84.39
2015	0	3679.00	3.19	17.29	55.15	30.05	85.20	85.20
2016	0	3679.00	3.19	17.55	55.98	30.05	86.03	86.03
2017	0	3679.00	3.19	17.81	56.82	30.05	86.87	86.87
2018	0	3679.00	3.19	18.08	57.67	30.05	87.72	87.72
2019	0	3679.00	3.19	18.35	58.54	30.05	88.59	88.59
2020	0	3679.00	3.19	18.63	59.42	30.05	89.47	89.47
2021	0	3679.00	3.19	18.91	60.31	30.05	90.36	90.36
2022	0	3679.00	3.19	19.19	61.21	30.05	91.26	91.26
2023	0	3679.00	3.19	19.48	62.13	30.05	92.18	92.18
NPV @10%	569.53	20027.16	17.37		274.45	169.37	443.82	1013.34

Power cost = US 5.06 cents/kWh

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

POWER COST & NET BACK VALUE - COAL, FUEL OIL & LIGNITE
Table A8.8: Lignite Fired Power Plant, Alternative Case 1
With low efficiency FGD
(Constant 1992 US Dollars)

ASSUMPTIONS:

Plant Factor - 70%
Efficiency - 33%
Size - 600 MW

Capital Cost - $1050/kw
Operating Cost - 4.0% of investment cost

Life - 25 years
Construction Time - 5 years

Year	Capital Cost ($ mil)	Power Generated GWh/Year	Volume of Lignite (mil tons)	Lignite CIF ($/ton)	Fuel Cost ($ mil)	Operating Cost ($ mil)	Total Oper. Cost ($ mil)	Total Cost ($ mil)
1994	126.00	0	0	0	0	0	0	126.00
1995	126.00	0	0	0	0	0	0	126.00
1996	126.00	0	0	0	0	0	0	126.00
1997	126.00	0	0	0	0	0	0	126.00
1998	126.00	0	0	0	0	0	0	126.00
1999	0	2759.00	2.40	14.52	34.85	25.20	60.05	60.05
2000	0	3311.00	2.87	14.65	42.05	25.20	67.25	67.25
2001	0	3679.00	3.19	14.78	47.15	25.20	72.35	72.35
2002	0	3679.00	3.19	14.92	47.59	25.20	72.79	72.79
2003	0	3679.00	3.19	15.05	48.01	25.20	73.21	73.21
2004	0	3679.00	3.19	15.19	48.46	25.20	73.66	73.66
2005	0	3679.00	3.19	15.32	48.87	25.20	74.07	74.07
2006	0	3679.00	3.19	15.51	49.48	25.20	74.68	74.68
2007	0	3679.00	3.19	15.76	50.27	25.20	75.47	75.47
2008	0	3679.00	3.19	16.01	51.07	25.20	76.27	76.27
2009	0	3679.00	3.19	16.27	51.90	25.20	77.10	77.10
2010	0	3679.00	3.19	16.53	52.73	25.20	77.93	77.93
2011	0	3679.00	3.19	16.29	51.97	25.20	77.17	77.17
2012	0	3679.00	3.19	16.53	52.74	25.20	77.94	77.94
2013	0	3679.00	3.19	16.78	53.54	25.20	78.74	78.74
2014	0	3679.00	3.19	17.03	54.34	25.20	79.54	79.54
2015	0	3679.00	3.19	17.29	55.15	25.20	80.35	80.35
2016	0	3679.00	3.19	17.55	55.98	25.20	81.18	81.18
2017	0	3679.00	3.19	17.81	56.82	25.20	82.02	82.02
2018	0	3679.00	3.19	18.08	57.67	25.20	82.87	82.87
2019	0	3679.00	3.19	18.35	58.54	25.20	83.74	83.74
2020	0	3679.00	3.19	18.63	59.42	25.20	84.62	84.62
2021	0	3679.00	3.19	18.91	60.31	25.20	85.51	85.51
2022	0	3679.00	3.19	19.19	61.21	25.20	86.41	86.41
2023	0	3679.00	3.19	19.48	62.13	25.20	87.33	87.33
NPV @10%	477.64	20027.16	17.37		274.45	142.03	416.48	894.12

Power cost = US 4.46 cents/kWh

Source: Bank mission estimate.

THAILAND
FUEL OPTION STUDY

POWER COST & NET BACK VALUE - COAL, FUEL OIL & LIGNITE
Table A8.9: Lignite Fired Power Plant, Alternative Case 2
Without FGD
(Constant 1992 US Dollars)

ASSUMPTIONS:

Plant Factor - 70%
Efficiency - 34.5%
Size - 600 MW

Capital Cost - $956/kw
Operating Cost - 4.0% of investment cost

Life - 25 years
Construction Time - 5 years

Year	Capital Cost ($ mil)	Power Generated GWh/Year	Volume of Lignite (mil tons)	Lignite CIF ($/ton)	Fuel Cost ($ mil)	Operating Cost ($ mil)	Total Oper. Cost ($ mil)	Total Cost ($ mil)
1994	114.72	0	0	0	0	0	0	114.72
1995	114.72	0	0	0	0	0	0	114.72
1996	114.72	0	0	0	0	0	0	114.72
1997	114.72	0	0	0	0	0	0	114.72
1998	114.72	0	0	0	0	0	0	114.72
1999	0	2759.00	2.29	14.52	33.25	22.94	56.19	56.19
2000	0	3311.00	2.75	14.65	40.29	22.94	63.23	63.23
2001	0	3679.00	3.05	14.78	45.08	22.94	68.02	68.02
2002	0	3679.00	3.05	14.92	45.51	22.94	68.45	68.45
2003	0	3679.00	3.05	15.05	45.90	22.94	68.84	68.84
2004	0	3679.00	3.05	15.19	46.33	22.94	69.27	69.27
2005	0	3679.00	3.05	15.32	46.73	22.94	69.67	69.67
2006	0	3679.00	3.05	15.51	47.31	22.94	70.25	70.25
2007	0	3679.00	3.05	15.76	48.07	22.94	71.01	71.01
2008	0	3679.00	3.05	16.01	48.83	22.94	71.77	71.77
2009	0	3679.00	3.05	16.27	49.62	22.94	72.56	72.56
2010	0	3679.00	3.05	16.53	50.42	22.94	73.36	73.36
2011	0	3679.00	3.05	16.29	49.68	22.94	72.62	72.62
2012	0	3679.00	3.05	16.53	50.43	22.94	73.37	73.37
2013	0	3679.00	3.05	16.78	51.19	22.94	74.13	74.13
2014	0	3679.00	3.05	17.03	51.95	22.94	74.89	74.89
2015	0	3679.00	3.05	17.29	52.73	22.94	75.67	75.67
2016	0	3679.00	3.05	17.55	53.52	22.94	76.46	76.46
2017	0	3679.00	3.05	17.81	54.33	22.94	77.27	77.27
2018	0	3679.00	3.05	18.08	55.14	22.94	78.08	78.08
2019	0	3679.00	3.05	18.35	55.97	22.94	78.91	78.91
2020	0	3679.00	3.05	18.63	56.81	22.94	79.75	79.75
2021	0	3679.00	3.05	18.91	57.66	22.94	80.60	80.60
2022	0	3679.00	3.05	19.19	58.53	22.94	81.47	81.47
2023	0	3679.00	3.05	19.48	59.40	22.94	82.34	82.34
NPV @10%	434.88	20027.16	16.61		262.41	129.29	391.71	826.58

Power cost = US 4.13 cents/kWh

Source: Bank mission estimate.

THAILAND

FUEL OPTION STUDY

Liquefied Natural Gas (LNG)

A. BASIC DATA

LNG Quantities

1. The imported LNG would be used in combined-cycle power plants working on base load. PTT does not plan to use the LNG-based gas to service industries, nor to replace other fuels in conventional power plants where it would not be competitive.

2. It is scheduled to increase combined-cycle plants from the present 2,650 MW to 13,500MW in 2003. If all of these power stations will be supplied with natural gas, the required flow rates would rise from the present 4 billion cubic meter (bcm) to 20 bcm in 2003. It has been assumed that only some of the future power plants will be supplied by LNG. For this study, two annual quantities have been selected; 5 bcm/year (4Mt/year) and 10 bcm/year (8Mt/year). These assumptions are compatible with current knowledge about future availability of LNG, and Thailand's power development program.

Delivery Points in Thailand

3. The scheduled power plants are primarily located in the vicinity of Bangkok. As agreed with the PTT, the delivery points adopted for the purposes of this study are not at the power plants (since the location of those plants to be installed after 2003 are not known), but rather at two consumption areas (Figure 1 of Annex 9); one around Ratburi (west of Bangkok) and the other around Bangpakong (east of Bangkok).

4. The Ratburi area is presently supplied from east Bangkok; the line transporting the gas is already saturated, a reinforcement is planned either onshore running north of Bangkok or offshore running south of Bangkok.

B. POTENTIAL SUPPLIERS

Introduction

5. The LNG market has undergone a substantial increase over the last few decades. Between 1979 and 1991, the world LNG trade volume has been sextupled. The constant growth of demand leads to the search for new LNG project and this creates a pressure to price increases for the gas itself and for the related equipment (liquefaction plants, tankers, etc).

6. The Far East market is dominated by Japan which is continuously increasing its use of LNG in power plants, the major consuming sector in this country. In addition, South Korea's and Taiwan's LNG markets are developing very fast. The following paragraphs review the various potential LNG suppliers for Thailand in the coming years from the view points of available reserves, existing and planned contracts, available LNG production capacity and possibility of expanding the plants.

Malaysia

7. Present reserves are 1,900 bcm and are increasing with new discoveries. The capacity of Bintulu liquefaction plant is 7.8 Mt/year, with its total production being sold to Japan. A second plant is scheduled to start in 1995, the production being intended for Japan, Taiwan and South Korea.

8. With the new proven reserves, a third plant is now the subject of a feasibility study. Its production, probably not available before 2000, does not seem to have been committed yet. So, Malaysia can be considered as a potential supplier in the medium term.

Indonesia

9. Reserves are around 3,000 bcm. This is the largest LNG exporter in the world (23.9Mt in 1992). Its main customers, in addition to Japan, are Korea (3.4Mt in 1992) and Taiwan (1.7Mt in 1992). Expansion of two plants are scheduled namely at Bontang where a 6th train is scheduled for end of 1993 and a 7th for 1997 (each 2.5Mt/year). The primary purpose of these units is to increase the quantities exported to existing customers and only after that, to possibly export to new customers.

10. Indonesia is also intending to develop the Natuna project but this has profitability problems due to high CO2 content. This project envisages a yearly quantity of 4Mt with expansion up to 12Mt, but most certainly will not be implemented before 2000. Recent discoveries by TOTAL could lead to the construction of an additional train.

11. Moreover, some of the contracts with Japan will terminate around year 2000. However, given Japan's rising demand, it is probable that these contracts will be renewed. In these conditions, Indonesia cannot, with present knowledge of its gas reserves and development plans, be considered as a potential supplier, even in medium term.

Qatar

12. Reserves are very large, more than 6,500 bcm. Four projects are identified. The first for Chubu Electric Power Co Inc which has a 4Mt/year production during the initial phase. The plant is designed for 6 Mt/year. Officially, it is still scheduled for commissioning around 1997 but start-up is likely to be delayed by one or two years. The second project, Qatar LNG Project, is 6 Mt/year for phase one and in principle is intended for Europe, primarily Italy. It should be commissioned before the end of this century, although agreement on price has encountered problems. The third project, Ras Laffan (QGPC: 70%; MOBIL: 30%) is for 10Mt/year and in principle is intended for the Far East (Japan excluded) and thus potentially for Thailand. The fourth project, with ELF and SUMITOMO

(4Mt/year), does not yet have a specific customer. Consequently, Qatar is a major potential supplier. All the above projects will use the gas from the giant reserves of North Field.

Brunei

13. Reserves are approximately 400 bcm. LNG is liquefied in a single plant at Lumut (6Mt/year) and is totally sold to Japan. The government seems to be considering an extension; however, given the relatively limited reserves, this could not be very large. Moreover, its production is already reserved for Japan. Therefore, Brunei appears doubtful as potential supplier to Thailand in the medium term.

Abu Dhabi

14. Production of the first two trains of Das Island liquefaction plant is intended for Japan, its sole customer. Same is true of the third train, the start-up of which is scheduled for April 1994. No other extensions seem to be planned in spite of huge reserves (more than 5,000 bcm).

Australia

15. Reserves are about 2,300 bcm. A third train is scheduled to start up this year, giving a yearly output of 7Mt and intended for Japan, although a few cargoes have been sent to Spain. Australia hopes to construct a new train in year 2000 and, if reserves prove sufficient, two new ones in 2005. Negotiations are in progress with Korea for a volume corresponding to one train (2Mt/year). So, LNG supply for Thailand is not foreseeable before 2005 and this depends on confirmation of reserves.

Oman

16. Known reserves are approximately 480 bcm. Oman plans to export 5Mt/year of LNG at earliest in 1999. No firm buyer is at present known. So, Oman appears to be a potential supplier.

Algeria/Nigeria/Venezuela

17. These countries have not been considered as their distance precludes the possibility of competitive prices for a long term contract.

Others

18. While there are other countries, such as Iran, Papua/New Guinea, Yemen and Sakhalin, prospects are insufficient for justifying their consideration for the near future.

Likely Suppliers

19. Qatar seems to be the most important potential supplier, even for large quantities, for the near future, around 2000.

20. Other countries can be considered as potential suppliers : Malaysia, due to the recent confirmation of new reserves; Oman, Abu Dhabi and also Australia, but around 2005. Depending on the evolution of political situation, Iran, with its huge reserves (the second in the world) could become a potential supplier at the beginning of the next century.

21. Even if presently there is no supply potential in Indonesia, evolution of the situation in this country has to be followed regularly. The quantities considered in this study could also be supplied by several producers.

C. SCENARIOS

22. The optimum selection of the LNG-receiving facilities will depend, in addition to the flow rates, on the geographical location of LNG potential suppliers and on the possible sites for LNG terminals.

LNG sources

23. Based on the above discussion (part B above), for the purpose of this study, two suppliers have been selected: (a) Qatar, which at the present time offers the largest potential; and (b) Malaysia, which does not seem to have large quantities to offer but has the advantage of being near-by and thus of providing low transportation costs.

Terminals

24. As concerns the location of the LNG-receiving terminal, six sites have been proposed (Figure 1 of Annex 9). Three of the sites (Ta Phut, Kao Bo Ya and Ao Phai) are located in the Rayong area; three others (Satun, Krabi and Ranong) are on the west coast of the country in the south of Burma. For the west coast terminals, only a supply from Qatar will be taken into consideration. Since the distances (by sea) between Qatar and these three terminals are approximately the same, they will not be differentiated in the study. For the Rayong area sites, two supply options are taken into consideration: one from Qatar and one from Malaysia. The marine distances were considered as similar for the three sites in Rayong area.

Onshore infrastructure

25. The connection by pipeline between the LNG receiving terminals in the west and the consumption centers around Bangkok area are based on the following assumptions:

(a) For the Ranong site, a 480 km long pipeline should be constructed to supply the Ratburi zone; and,

(b) For Krabi and Satun, first, a connection by land of 175 km and 105 km, respectively, are needed to cross the Peninsula, and then transmission to Rayong in north, through the existing Erawan offshore transmission system and the planned expansion of this system.

26. It is not possible to project the state of saturation of these off shore pipeline networks at the time when LNG will be imported, because of large number of possible solutions for the transportation of domestic and imported gas. Therefore, it is not possible to quantify the cost related to the extension or expansion of networks required by the import of LNG. However, for Krabi and Satun sites, connection costs will probably not be lower than the cost of the Ranong-Ratburi connection, given the length and the unit costs of the offshore portion, and the need to reinforce the connection between the east of Bangkok (where most of the gas arrives already) and the west of Bangkok. The study will therefore consider the site of Ranong as a base case.[1/] However, the three sites of the Rayong region will be studied individually.

27. Given that the network towards Bang Pakong is already saturated and that an east-west reinforcement is already necessary, the direct supply of the Ratburi region should be encouraged. For the 4 Mt/y option, all the gas is assumed to be sent towards Ratburi by offshore pipeline and for the 8 Mt option, it is assumed that the supply will be equally distributed between Ratburi and Bang Pakong.

28. The studied scenarios for each option (4 Mt/y and 8Mt/y), therefore, are:

Source of Supply	Terminal Location
Qatar	Map Ta Phut (Rayong region)
Qatar	Kao Bo Ya (Rayong region)
Qatar	Ao Phai (Rayong region)
Qatar	Ranong (west coast)
Malaysia	Map Ta Phut
Malaysia	Kao Bo Ya
Malaysia	Ao Phai

1/ It should be noted that additional studies (including site evaluation) are required to compare the three potential sites. Furthermore, "flow simulation model" should be used to optimize the size and structure of both onshore and offshore gas transmission system. Given the lack of time and data, these studies are beyond the scope of this mission.

D. MARITIME TRANSPORTATION

Design of LNG Transportation

29. With respect to maritime transportation, three scenarios are considered: (a) Case 1, from Qatar to one of the three sites around Rayong; (b) Case 2, from Qatar to one of the three sites along the west coast (Ranong, Krabi or Satun); and (c) Case 3, from Malaysia (Bintulu) to one of the three sites around Rayong. The maritime distances are 4,300 miles for case 1; 3,200 miles for case 2; and 1,050 miles for case 3.

30. Taking into account the speed of commercial LNG tankers, the necessary reduction of that speed during the crossing of Malacca strait, the duration of port calls and the tanker maintenance times, a LNG tanker can perform, within a year, 15.6 trips for case 1; 22.2 trips for case 2; and 51.4 trips for case 3.

31. Given that the gas quantities to be transported (4Mt and 8Mt) do not correspond to a full utilization of standard size tankers (135,000m3), to calculate the unit transportation cost of LNG for each case, the number of tankers for each trip length is chosen such as to get as close as possible to the theoretical yearly quantity of LNG delivered. The real quantities delivered will then be deducted from the transport capacity corresponding to the number of tankers chosen. Taking into account the boil-off, the theoretical delivered quantities are:

Case 1	3.8Mt/year with 4 tankers of 135,000m3
	7.6Mt/year with 8 tankers of 135,000m3
Case 2	4.1 xMt/year with 3 tankers of 135,000m3
	8.2 xMt/year with 6 tankers of 135,000m3
Case 3	3.2 xMt/year with 1 tanker of 135,000m3
	6.4 xMt/year with 2 tankers of 135,000m3

Costs

32. **Investment costs**. An analysis of the market, based on recently signed building contracts for LNG tankers, shows that the cost of a 135,000 m3 tanker is about US$270 million, including engineering studies and commissioning. This amount does not include financial costs during construction.[2/]

2/ It must be noted that the costs of tankers have been subject to significant variations in the past years, so a sensitivity study has to be carried out to estimate the effect of such variations on the gas transportation costs.

33. **Operating costs**. The operating costs can be split into two parts: (a) fixed annual expenses; and (b) variable annual expenses.

34. The fixed operating costs of LNG tankers include:

(a) A crew of about 30 people;

(b) Maintenance of LNG tankers, including ongoing maintenance (technical and commercial management of the ship) and maintenance in dry-docking conditions, once every two years; and

(c) The insurance for a LNG tanker, covering four types of risks: accident on hull and engine; civil liability; rent losses; and war risk.

35. The variable operating costs of LNG tankers include: (a) energy for propulsion; (b) other consumable products; and (c) ports dues and services.

36. **Energy for Propulsion**. The boilers of LNG tankers can be fed either with fuel oil, or with the boil-off gas generated in the cargo tanks, or with both. At nominal speed (18,5 knots), boil-off is not enough and fuel oil is used to supplement the fuel requirements. The propulsion cost of the ship has been evaluated based on boil-off rate of 0.15% per day of the tanks capacity, cost of marine fuel oil at US$120 per ton, and cost of boil-off gas at US$2.5 per MMBtu.

37. **Other consumable products**. Other consumables mainly include diesel oil and liquid nitrogen. Only liquid nitrogen is considered in the calculations.

38. **Port dues and services**. Port dues and services include pilotage, towage, boatmen (ship mooring), port taxes and administrative expenses such as shipping agent.

39. **Total Maritime Transportation costs**. Table 1 of this Annex provides the unit cost of maritime transportation. As can be seen from Table 1, the cost is almost independent from the transported quantities. The slight difference between 4Mt and 8Mt per year is due to differences in the scheduling of tanker construction expenses, which is not significant (the present calculations do not take into account a build-up phase in delivered quantities).

Table A9.1 - Total Cost of Maritime Transportation
(US$ million)

Number of Tankers	Case 1		Case 2		Case 3	
	4	8	3	6	1	2
Total Investment	1,080	2,160	810	1,620	270	540
Fixed yearly operating costs	30	60	22.5	45	7.5	15
Variable yearly operating costs	32	64	27.3	54.6	13.4	26.9
Total yearly operating costs	62	124	49.8	99.6	20.9	41.9
Annual delivered quantity (million ton of LNG)	3.8	7.6	4.1	8.2	3.2	6.4
Transportation cost US$/MMBtu	1.25	1.27	0.87	0.88	0.38	0.40

Source: Bank mission estimate.

Construction schedule of LNG Tankers

40. It is estimated that 4 years are necessary before delivery of the first 135,000 m3 LNG tanker. This includes: (a) tanker specifications and selection of a short list of shipyards (2 months); (b) qualification of shipyards (2 months); (c) call for tenders (3 months); (d) bid analysis (5 months until the building contract signature); and (e) construction period (3 years).

41. The delivery of other tankers can follow at 3 to 6 months intervals. These durations correspond to the present situation of tanker building market. Only 29 shipyards have the necessary license to build such ships and, among them, only 10 have the necessary experience. If we consider the large number of LNG projects under study, this shipbuilding capacity could be quickly saturated and tanker availability may become a bottleneck to LNG projects development.

Organizational Aspect of Shipping LNG

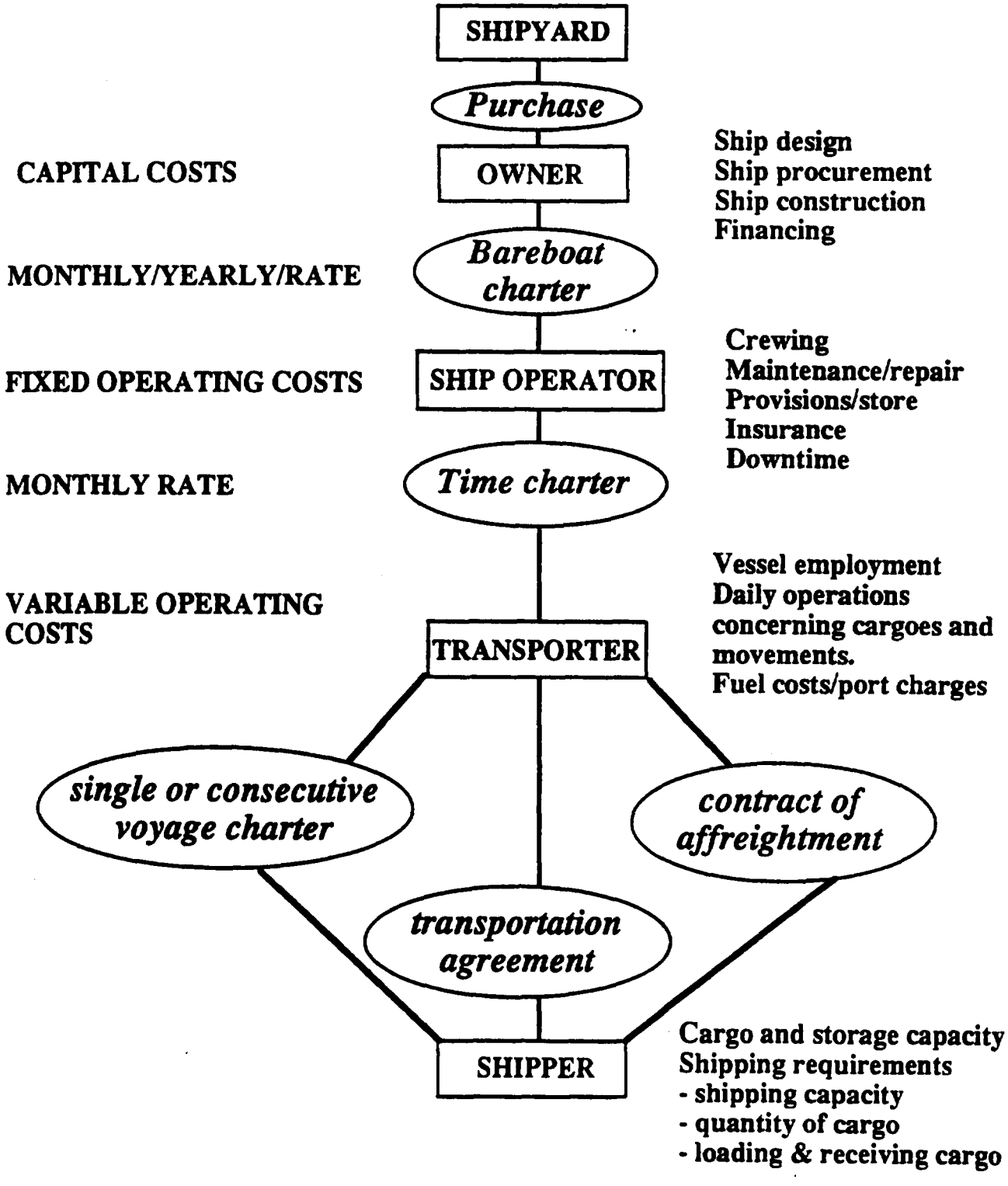
42. Marine transportation can be handled either by the buyer (FOB contract) or by the seller (CIF contract). Figure 2 of this Annex shows a schematic diagram of the marine transportation organization which includes shipyard, owner, ship operator, transporter and shipper.

43. Generally, the company (buyer or seller) in charge of marine transportation (the shipper) pays both, a monthly rate corresponding to the fixed costs (capital cost depreciation, crew, maintenance, etc.) and the variable operating costs (fuel, port fees, etc.). This will have the advantage of not having to raise the financing for ship buying.

44. Nevertheless, buyer or seller can also be involved as ship owner or operator. Being more involved in marine transportation allows a better control of the costs and can help avoid to bear excessive margins if the market is under pressure.

45. The comparison between being the shipper or the owner, requires a much more detailed analysis of the financial and structural aspects. However, the marine transportation cost estimate will not be significantly affected by the result of such a analysis.

VESSEL PROCUREMENT



E. REGASIFICATION FACILITIES

Design

46. Regasification terminals are built with modular units and can be adapted to the required gas quantities to be stored and regasified. Implementation of the regasification facilities in two or three steps is quite feasible and has been experimented in many terminals (France and Spain).

47. **Send-out flow rate**. As discussed before, two annual send-out flow rates are considered: 4Mt/year and 8Mt/year. As LNG is assumed to be dedicated to combined cycle power plants used as base load, maximum LNG send-out flow rate is taken equal to 120% of the average hourly delivery; namely, 580MMSCF/D (685,000m3/h) for 4Mt/year and 1,160MMSCF/D (1,370,000m3/h) for 8Mt/year.

48. **Storage volume**. LNG storage has four functions:

(a) reception of the total cargo of the largest LNG tanker unloading at the terminal;

(b) buffer storage while awaiting the next delivery (normal operation);

(c) security storage to ensure continuity of send-out flow rate when the schedule of supply is disrupted over a short period (e.g. delay due to poor navigational conditions); and

(d) strategic reserve so as to be able to cope with a long interruption in LNG deliveries.

49. Because there is no requirement for strategic reserves in the Thailand's current regulation, and due to the existence of other gas supply sources, the strategic reserve function has not been considered in this analysis. Given the size of the LNG tankers and the send-out capacity, the theoretical LNG storage volume required in the regasification terminal is 280,000 m3 for 4Mt/year and 425,000 m3 for 8Mt/year. For the purpose of this study, we will consider two 140,000 m3 tanks for 4Mt/year and three 140,000 m3 tanks for 8Mt/year.

50. **Regasification facilities**. Each vaporizing line includes primary pumps (inside the tanks), secondary pumps (high pressure pumps) and vaporizers. For safety purposes, it is assumed that a regasification line would be provided with stand-by equipment. In industry practice, the base send-out gas flow rate is ensured by open-rack vaporizers which has low operating costs. Stand-by equipment consist of submerged (combustion) vaporizers, the operation of which is more expensive. The number of lines and required equipment shall be designed according to the specified storage capacity and send-out flow rate. As the terminal will be connected to the gas network, the send-out pressure is taken equal to 80 bar.

51. **Marine facilities**. Marine facilities are assumed to be designed in accordance with international standards on environmental protection. Dredgings are supposed to reach a water depth of

14 meter, necessary to receive 135000 m3 LNG tankers (maximum ship draught of 11.7m). One jetty is assumed to be built for the 4Mt/year terminal, and two for the 8Mt option.

52. **Terminal area**. The area needed for the facilities depends on the number of tanks and also on the design options. For example, the distance between the tanks could be 110m for in-ground tanks, but more than 200m for above ground tanks with retention pond. An area of 50 hectares (125 acres) for the 8Mt/year terminal and 40 hectares (100 acres) for the 4Mt/year terminal is assumed in this study. These areas allow to build the required number of above ground tanks plus one, if needed.

Site Assessment

53. Six sites proposed by PTT were considered:

- Map Ta Phut near Rayong
- Kao Bo Ya near Rayong
- Ao Phai (north of Kao Bo Ya)
- Ranong on the west coast
- Krabi on the west coast
- Satun on the west coast

54. The last three have not been visited by the Bank mission and, therefore, the information is not sufficient to assess their suitability. The other sites, which have been visited, are examined below.

55. **Map Ta Phut**. This site is an industrial estate. Facilities are built on a reclaimed area. Up to now, all areas are committed, but according to port authorities extensions are possible. As the site is exposed to southern winds, the area dedicated to LNG facilities should be protected by a dike which seems to be already in the plan, according to information from port authorities. Present harbor fees are rather high and include the use of many facilities (cranes, railways etc.).

56. **Kao Bo Ya**. Since there is not enough space available in the harbor, a proposal has been made to reclaim land between the shore and along the existing berths (for oil and LPG). The feasibility of the reclaimed area need to be confirmed with respect to the soil condition and the effects of possible water currents. An emergency (escape) road has to be built toward the refinery. The LPG jetty should be relocated to, at least, the other side of the petroleum pier. Meteorological conditions are quite good and that has been proved with the experience of the existing petroleum and LPG receiving terminals. Only a few days in the year conditions are beyond acceptable criteria.

57. **Ao Phai (coal site)**. This site could be a potential site for the LNG facilities if the coal facilities are not built. This site is well protected with respect to meteorological conditions. The coal facilities were planned to be built on a reclaimed area of about the same size as for the LNG facilities.

58. One advantage common to the three sites is that they are in industrial setting far from public buildings. Around all three sites, marine traffic is significant. From this point of view, Map Ta Phut is safer because the jetty will be protected by a dike.

59. Regarding the safety distances, the figures vary significantly according to the design options and applicable codes. A catastrophic event such as the break of the double containment system of the LNG tank, should only be considered as ultimate case in the design of the emergency plans of the involved area.

Costs

60. **Investment Costs**. The investment cost includes:

(a) Land preparation. Cost estimates given to the mission during the visit of the potential sites show some discrepancies. Regarding the Map Ta Phut site, all sources agree on an approximate cost of US$450,000 per hectare lump sum. To this cost must be added an annual fee for harbor authorities. The figure for Kao Bo Ya site have been given by the Laem Chabang Port authorities, based on the cost of the port construction. This cost has been corrected to take into account the slope of the subsea ground, resulting in US$350,000 per hectare. As the land belongs to PTT, no annual fee is considered. Regarding the Ao Phai site, the only available figure, Baht 2,4 billion for 50 hectares, seems very high and may include some equipment specific to coal facilities. Therefore, for this site the same cost as for Kao Bo Ya has been used. Regarding the three other sites under consideration on western coast of the country, as no reliable information is available, the Map Ta Phut cost are taken for the purpose of economic calculation.

(b) Marine facilities. The cost includes jetty and berths and the unloading facilities. For the Ao Phai and Kao Bo Ya sites, a jetty has to be built in order to reach adequately deep water.

(c) Storage. The cost of facilities includes the tanks themselves, retention ponds and the corresponding safety facilities, connecting piping, pipe racks, electrical and instrumentation up to retention pond limit. The cost is based on above ground tanks technique with pre-stressed concrete outer tank. If in-ground tanks are selected for safety reasons; for example, the cost could be increased up to 1.5 time the last price of above ground tanks.

(d) Vaporization and sending-out. The cost are calculated for the design flow rate and takes into account stand-by equipment.

(e) Boil-off handling system. This investment cost includes pipes, cables, electric stations, facilities for various fluids (compressed air, liquid and gaseous nitrogen, water, service gas etc.), safety facilities, buildings.

61. **Operating costs**. The operating costs of the LNG terminals consist of fixed and variable costs.

62. The fixed annual costs include:

(a) Staffing. The expected organization would require about 70 staff for 5 bcm per year gas flow and 90 staff for 10 bcm gas flow. The number of staff also depends on the maintenance work "subcontracted" to external companies;

(b) Maintenance. This cost represents the purchase of the required spare parts, the specific expenses for maintenance work, including sub-contractors contract; and

(c) Insurance and other operating costs

63. The variable annual costs include:

(a) Electric power. This cost is estimated on the basis of projected annual electric consumptions at US¢5 per kWh; and

(b) Consumables. This includes the odorization products, treatment of the water used in the vaporizers, diesel oil, dry chemical powder, CO2 and water.

64. **Total regasification costs**. To calculate the total regasification costs, two types of sites were assumed: (a) sites on reclaimed lands such as Kao Bo Ya and Ao Phai; and (b) sites within a port premises, such as Map Ta Phut. In the absence of more accurate information, the most cost sites were assimilated in this type of site.

65. Calculations were made for two send-out rates, namely for 4 Mt/y and 8 Mt/y. Table 2 below shows the result of regasification costs analyses. While Table 2 shows little cost difference between various sites (at least at this broad level of analyses), it clearly shows the effect of scale: US$0.5 per MMBtu for the 4Mt/year project; and US$0.38 per MMBtu for the 8Mt/year project.

Table A9.2 - TOTAL COSTS OF REGASIFICATION
(US$ million)

Location	Kao Bo Ya & Ao Phai		Map Ta Phut & West Coast	
Plant Size	4 Mt/y	8 Mt/y	4 Mt/y	8 Mt/y
Investment Costs				
Land Preparation	15	20	18	25
Marine Facilities	50	100	30	60
Storage	150	230	150	230
Vaporization and send out	85	140	87	140
Boil off	25	40	25	40
Utilities	190	240	190	240
Total investment costs	515	770	500	735
Yearly fixed operating expenses	20.6	30.3	22	31.6
Yearly variable operating expenses	4	7.5	4	7.5
Yearly total operating expenses	24.6	37.8	26	39.1
LNG terminal cost US$ per MMBtu	0.51	0.38	0.50	0.37

Source: Bank mission estimate.

F. INLAND TRANSMISSION

Design Basis

66. The transmission network connecting the LNG terminal to the consumption centers is designed based on the following assumptions:

(a) Flow rates: for 4 Mt/y; 685,000 m3/h or 550 MMSCFD; for 8 Mt/y; 1,370,000 m3/h or 1,100 MMSCFD;

(b) Pressure at terminal outlet: 1200PSI; and
(c) Delivery pressure at the end-user: 500 PSI.

67. The results of the pipeline sizing calculations are:

(a) Ranong site: 4 Mt/y : 28" diameter, 480 km long pipeline to Ratburi
2 x 10 MW compressor stations.

8 Mt/y : 36" diameter, 480 km long pipeline
3 x 14 MW compressor stations.

(b) Map Ta Phut site:	4 Mt/y :	28" diameter, 190 km long pipeline (of which 110 km are offshore - Ratburi branch).
	8 Mt/y :	36" diameter, 35 km long pipeline (common mainline); 32" diameter, 155 km long pipeline (Ratburi branch, 110 km offshore); and 20" diameter, 75 km long pipeline (Bangpakong branch).
(c) Kao Bo Ya site:	4 Mt/y :	24" diameter, 140 km long pipeline.
	8 Mt/y :	30" diameter, 140 km long pipeline (Ratburi branch, 110 km offshore); and 20" diameter, 75 km long pipeline (Bangpakong branch).
(d) Ao Phai site:	4 Mt/y :	24" diameter, 140 km long pipeline.
	8 Mt/y :	30" diameter, 140 km long pipeline (Ratburi branch, 110 km offshore); and 16" diameter, 45 km long pipeline (Bangpakong branch).

Costs

68. **Investment Costs**. The investment costs for various configuration assumed in the above analyses are:

(a) Ranong site:	4 Mt/y :	pipeline	US$320 million
		station	US$ 45 million
		Total	US$365 million
	8 Mt/y :	pipeline	US$450 million
		station	US$ 90 million
		Total	US$540 million
(b) Map Ta Phut site:	4 Mt/y :	pipeline	US$150 million
	8 Mt/y :	pipeline	US$210 million
(c) Kao Bo Ya site:	4 Mt/y :	pipeline	US$ 95 million
	8 Mt/y	pipeline	US$165 million
(d) AO PHAI site	4 Mt/y :	pipeline	US$ 95 million
	8 Mt/y :	pipeline	US$145 million

69. **Operating Costs**. The operating costs include personnel, maintenance, insurance, spare parts, for pipelines and compressor stations.

70. **Total Gas Transmission Costs**. Results are given in Table 3 below:

Table A9.3 - TOTAL GAS TRANSMISSION COSTS
(US$ million)

Location	Ranong		Map Ta Phut		Kao Bo Ya		Ao Phai	
Size	4Mt	8Mt	4Mt	8Mt	4Mt	8Mt	4Mt	8Mt
Investment Costs	365	540	150	210	95	165	95	145
Yearly operating costs	14.4	27.5	1.8	2.5	1.1	2	1.1	1.8
Cost of Pipeline transmission (US$ per MMbtu)	0.33	0.26	0.12	0.08	0.07	0.06	0.07	0.06

Source: Bank mission estimate.

G. EVALUATION RESULT

71. Table 4 shows the various cost elements for each option discussed above, including maritime transportation, regasification and inland transmission.

Table A9.4 - TOTAL COSTS BETWEEN LIQUEFACTION PLANT AND CONSUMPTION POINT
(US$/MMBtu)

Option	Supplier	Terminal Site	Cost of Sea Transportation	Regasification and Terminal Cost	Cost of Inland Transportation	Total
4 Mt/y	Qatar	Map Ta Phut	1.25	0.5	0.12	1.87
4 Mt/y	Qatar	Kao Bo Ya	1.25	0.51	0.07	1.84
4 Mt/y	Qatar	Ao Phai	1.25	0.51	0.07	1.83
4 Mt/y	Qatar	Ranong	0.87	0.50	0.33	1.70
4 Mt/y	Malaysia	Map Ta Phut	0.38	0.5	0.12	1.00
4 Mt/y	Malaysia	Kao Bo Ya	0.38	0.51	0.07	0.96
4 Mt/y	Malaysia	Ao Phai	0.38	0.51	0.07	0.96
8 Mt/y	Qatar	Map Ta Phut	1.27	0.37	0.08	1.72
8 Mt/y	Qatar	Kao Bo Ya	1.27	0.38	0.06	1.71
8 Mt/y	Qatar	Ao Phai	1.27	0.38	0.06	1.71
8 Mt/y	Qatar	Ranong	0.88	0.37	0.26	1.51
8 Mt/y	Malaysia	Map Ta Phut	0.40	0.37	0.08	0.85
8 Mt/y	Malaysia	Kao Bo Ya	0.40	0.38	0.06	0.84
8 Mt/y	Malaysia	Ao Phai	0.40	0.38	0.06	0.84

Source: Bank mission estimate.

72. The following preliminary conclusions can be drawn from Table 4, above:

(a) From a transportation point of view, Malaysia offers, in comparison with Persian Gulf sources, a very clear advantage of about US$0.9 per MMBtu.

(b) For LNG coming from Persian Gulf, the best solution is to receive the LNG tankers on the west coast and not in the Gulf of Thailand. This is because the increase in inland transportation cost is less than the increase in LNG maritime transportation cost (US$0.2 per MMBtu, compared to US$0.4 per MMBtu).

(c) The total unit transportation cost, from the loading harbor up to the final customer is sensitive to the size of the project (4Mt or 8Mt). However, the size effects only the LNG terminal and the pipelines costs in Thailand, which represent only 35 to 45% of the total cost.

(d) Based on the above cost, the economic feasibility of LNG supply to Thailand warrants a closer look and a more detailed evaluation.

73. Considering that the costs of power generation, either by coal or by gas-fired combined-cycle plant, reaches to about US¢5.4 per kWh (assuming a coal price of US$50/ton CIF power plant and a (discount rate of 12%), such an electricity price corresponds to a maximum gas price (CIF plant) of about US$4.7-US$5.0 per MMBtu. Whatever the location of the future LNG terminal is, the regasification cost and transportation cost in Thailand are lower than US$0.8 per MMBtu. This would give a net back value for LNG (CIF terminal) of about US$3.9-US$4.2 per MMBtu. This value is higher than the present CIF price of LNG in the Far East which is US$3.6 - US$3.7 per MMBtu and moreover, this price is related to countries significantly farther from LNG sources than Thailand.

74. Therefore, LNG appears to be a feasible option that would need to be investigated further, to better assess the costs (particularly, those of the western coast terminal) and timing of supply which could have a considerable impact on the feasibility of the project (build-up of consumption).

H. OTHER ASPECTS

Institutions

75. **Introduction**. LNG projects are integrated systems with strong technical, institutional and financial links between upstream (gas production, liquefaction and transport) and the downstream activities (storage, regasification and marketing). This is reflected in the number of agreements linking the various parties to the project and the dedication of reserves, production capacity and ships to specific contracts having an economic life of more than 20 years.

76. Negotiating these agreements and building up a credible financing plan may require several years. In addition, it requires a significant exchange of information between the seller and its associated companies or partners and the buyer(s). It is, therefore, important for the buyer to have defined an LNG development strategy before starting negotiations with potential suppliers. In the following sections some issues are discussed, which in our opinion need to be resolved before contacts with suppliers are initiated. They deal with problems of responsibilities in LNG chain actors and the contracts characteristics.

77. **Responsibility-sharing among the LNG chain actors**. The main actors in the LNG transaction chain are:

(a) The LNG supplier. The supplier bears the reserve risk and the risk of the construction cost of production and liquefaction facilities of natural gas. Furthermore he has two other main risks: (i) to sell smaller quantities than forecasted. He usually transfers this risk to the buyer through the long duration (more than 20 years) contract, and the "take or pay" clause of the LNG purchase contract; (ii) the evolution of LNG price because during the project life, the price may not cover the amortization of capital costs of gas fields development and liquefaction plant. This risk usually remains with LNG supplier since escalation formula of LNG price generally aims at covering the economic risk of the buyer (competitiveness of LNG with other fuels on end-users market).

(b) The LNG transporter. The transport is generally either by the LNG supplier (CIF or Ex-ship supply contract), or by the LNG buyer (FOB supply contract). A table showing a transportation scheme is attached hereafter.

(c) The LNG buyer. The buyer is generally a gas company which accepts the main risks of the project. This includes (i) risk of "quantities", including the risk of "take or pay" clause and of a bad amortization of the cost of the LNG terminal and other necessary investments. These can be reduced either by legal arrangements (import monopoly for example) or by contractual clauses with the main end-users (take or pay clause in the sale contract to power generation company for example); (ii) risk of non-competitiveness with other fuels on the final market. This risk, already reduced by adequate escalation formula, can be partially transferred to the end-users by long term sale contract (with power producers or local distribution companies); (iii) risk on investment costs of gas facilities (LNG terminal and gas pipelines). This risk can be partially covered by turn-key construction contracts; and (iv) other risks such as changes in energy taxes policy, or change in exchange rates between local and foreign currencies (which can be reduced by long term agreement with the local government by adequate financing procedures).

Gas supply contracts

78. LNG supply contracts are tailored after gas sales contracts between the producer and the gas distribution companies. In addition, they include clauses related to the shipping aspects of an LNG

and on the coordination and sharing of information between upstream and downstream activities. The main clauses of a Gas Purchase Agreement (GPA) are described in the following paragraphs.

79. **Delivery terms**. There are three main delivery terms in LNG transportation: FOB, CIF, and Ex-ship. FOB contracts are favored when gas companies are customers, or when buyer promotes its own LNG industry. CIF/Ex-ship contracts are favored when "international" companies are sellers, or when utility companies are buyers, or when the buyer is signing its first LNG purchase contract.

80. **Scope of the GPA**. A GPA generally includes the expected duration of the agreement (usually 20 to 25 years) possibly divided into separate time slices during which the respective obligations of the seller and the buyer(s) may vary. It also includes statements such as the seller's obligation to sell and buyer's obligations to "take or pay"[3/], as well as statements on dedication of reserves, production capacity, ships by the seller (CIF contacts) or by the buyer (FOB contracts), and of receiving terminal capacity (by the buyer).

81. **Volumes of sales**. This is normally defined for 20 to 25 years (possibly with different volumes for different periods). The GPA specifies the annual contracted volume which has to be lifted within plus or minus 5 to 10%. In addition, minimum and maximum purchases are agreed over a given period of time. It is specified for example that the buyer would not lift less than 20% or more than 30% of the annual contracted volumes within a period of three consecutive months.

82. **Quality of gas**. The quality of gas delivered and the conditions within which the gas quality will be established are normally spelled out in great details in an attachment to the contract, defining the calorific value of the gas (which forms the basis for invoicing and payments), and the maximum level of impurities or inerts.

83. **Shipment and facilities**. The seller undertakes to provide "Full Cargo Lots" and, in CIF contracts, to transport LNG in dedicated tankers to specified terminals. The buyer undertakes to provide port, berthing and operational facilities suitable for the safe operation of the tanker while calling at the terminal. The specifications of the unloading facilities are spelled out and the contract specifies the maximum unloading time for tankers allocated to the contract (usually less than 12 hours) and the level of port charges and the escalation formulae as well as the maximum boil-off rate during the voyage.

84. **Price**. The base price is the result of negotiation between the seller and the buyer, as is the escalation formula. A typical escalation formula would link LNG prices to 20% of the CIF price of imported crude in the buyer country; 20% of the consumer price of low sulphur heavy fuel oil; 20% of the consumer price of light fuel oil; 30% of the price index of commercial products; and 10% of the

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3/ Take or pay obligations are still the rule for GPA although considerable flexibility has been introduced over time on the share of total off-take covered by the take or pay (originally close to 100%, now closer to 60-70%). Flexibility has also been introduced in the area of Make Up LNG (LNG paid for by the buyer under the take or pay provision but not lifted), that can now be recovered over a longer period of time.

whole sale price index. Other formulae have been used, based on the structure of the end-use market in the buyer's country.

85. **Payments**. Normally, within 90 days after receiving the Bill of Lading.

86. **Recent evolution**. Uncertain market conditions and competition have in recent years introduced more flexibility in LNG transaction and the concept of "take-or-pay" has been challenged for new LNG agreements with existing suppliers. This agreement is based on direct marketing of LNG by the buyer on a free market. There is no "take-or-pay" obligations and LNG is imported if the marketing efforts are successful at prevailing market prices. The seller and the buyer share the market risk and rewards according to pre-agreed rules. However, this type of agreement has been made possible because both the seller and the buyer had spare liquefaction and regasification capacity. It is doubtful that a "grass root" project could be built on these principles since the financing agencies are likely to require long term purchase contracts to ensure adequate coverage of debt service. Nevertheless, it seems that the trend is towards more flexible contracts.

LNG Price

87. **General Considerations**. The LNG industry is very capital intensive. The promoters of LNG projects demand guarantees to ensure financial profitability along the life of the project. This is particularly important in a very volatile energy price market, as during the 1970s and 1980s which had led to the re-negotiation of LNG prices in line with the variations in the price of other fuels internationally traded.

88. **Evolution of LNG prices**. In the 1970s, the basic price indexing terms referred to the prices of oil products in the importing countries (heavy fuel oil and gas oil which were substituted by gas). After the second oil shock, in 1979, some producing countries claimed strict parity between crude prices and gas prices (on thermal equivalence). In 1980, the indexing on crude prices (imported by the LNG importing country or produced by the LNG supplier) became the rule in LNG contracts. The indexing was on the government selling price (GSP) of crude. At that time, some exporters even asked for gas prices to be linked to oil prices on a FOB basis (corrected for thermal efficiency). The collapse of crude prices in November 1986 has led to a multiplicity of provisional price agreements, based on the netback value of crude, since the GSPs no longer reflected market prices. At the beginning of 1987, OPEC established new official prices which became the new reference in the determination of the LNG price.

89. **Regional specificities in LNG prices**. Historically, the basic price indexing terms have been very different on the three markets: Japan, USA and Europe. The last trends for these markets are:

(a) In Japan, indexing terms depend on the suppliers. Prices are linked to GSP (Government Selling Price) or to the spot prices of crude.

(b) In the USA, LNG price is usually the higher of: (i) minimum price indexed on spot gas price in the US; (ii) reference price indexed on gas oil, fuel oil and interstate gas prices; and (iii) price evolving as a function of the selling price by the US companies.

(c) In Europe, LNG price is indexed on netback value of a cocktail of crude, determined by the spot prices of products referenced in Europe.

90. **Future trends**. Since various indexation formulae are used to adjust LNG prices, consequently, it is difficult to give an assessment of future LNG price for Thailand because price fluctuations will depend on the negotiated indexation. In addition, the durability of the link between gas and oil prices need to be questioned. The penetration of natural gas in power generation suggests a growing relationship between coal and gas prices. Besides, economic and technological advantages of combined-cycle power plants should justify a premium for gas over coal.

Safety Aspects of LNG Import and Regasification

91. LNG worldwide trade has reached a high degree of reliability and LNG can be considered with a good security of supply. Since the industry began in 1964 (Algerian LNG to UK and France), LNG supply has appeared as a highly reliable source of energy.

92. No major accident has been recorded in all the facilities in the world since that date. Liquefaction plants, LNG tankers and regasification terminals have very sophisticated design and materials. The main risk related to land facilities is the spillage of large quantities of LNG and inflammation of resulting vapor clouds. However, due to a number of tests and large scale experimentation, the behavior of LNG in case of spillage is now well known and it is possible to predict what will be the consequences of a spillage (vaporization, vapor cloud extension and heat radiation in case of inflammation). LNG facilities at the design stage are usually the subject of safety studies, including the examining of all the risks and taking the necessary safety measures.

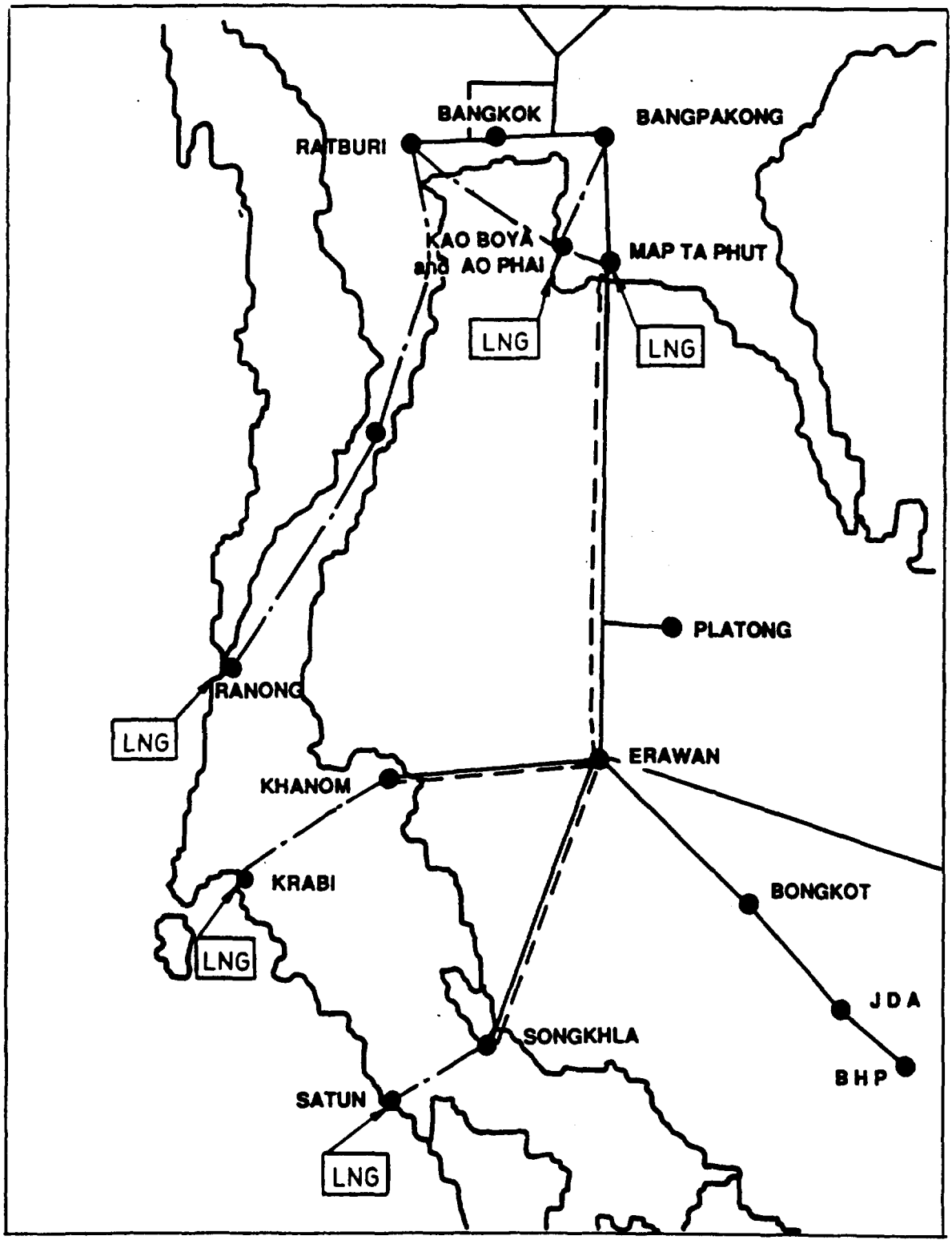
93. With respect to technical aspect of LNG facilities, constantly updated codes and standards give the guidelines for a safe design. LNG tanks, when they are not in-ground have a double containment system: a first metallic inner tank (membrane or self supporting) and a pre-stressed concrete outer tank able to contain LNG in case of failure of the inner tank. A retention pond around these tanks are also often constructed.

94. Regarding the tankers, the double hull design has proved to be very safe even in case of grounding.[4/]

95. As a conclusion, an LNG chain is very reliable, provided that companies involved in engineering and implementing such facilities have a high level of expertise and that operating people are well trained and assisted by a company well experimented in the LNG field.

4/ Grounding of membrane tanker Paul Kaiser in 1979.

POTENTIAL SITES AND CONNECTING PIPES

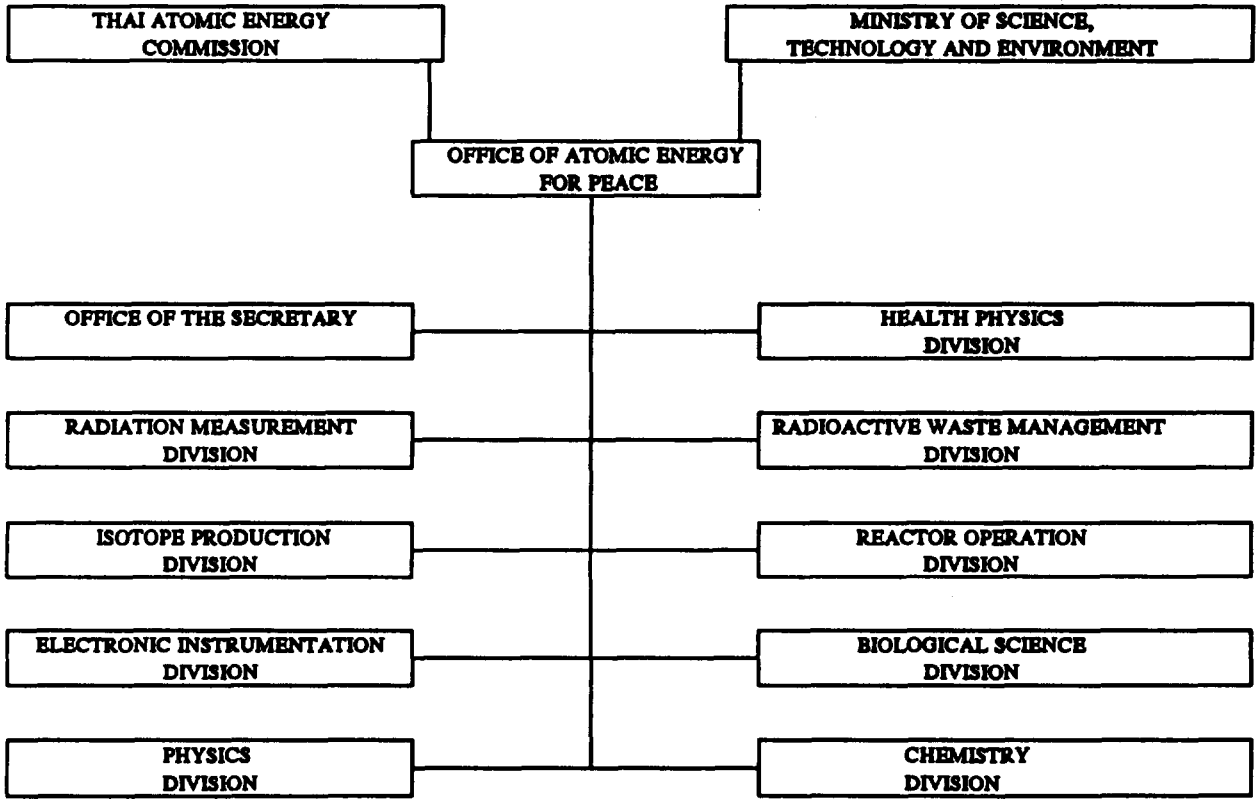


LEGEND

- EXISTING OR PLANNED PIPELINES
- PIPELINES TO BE INSTALLED
- REINFORCEMENT TO BE STUDIED

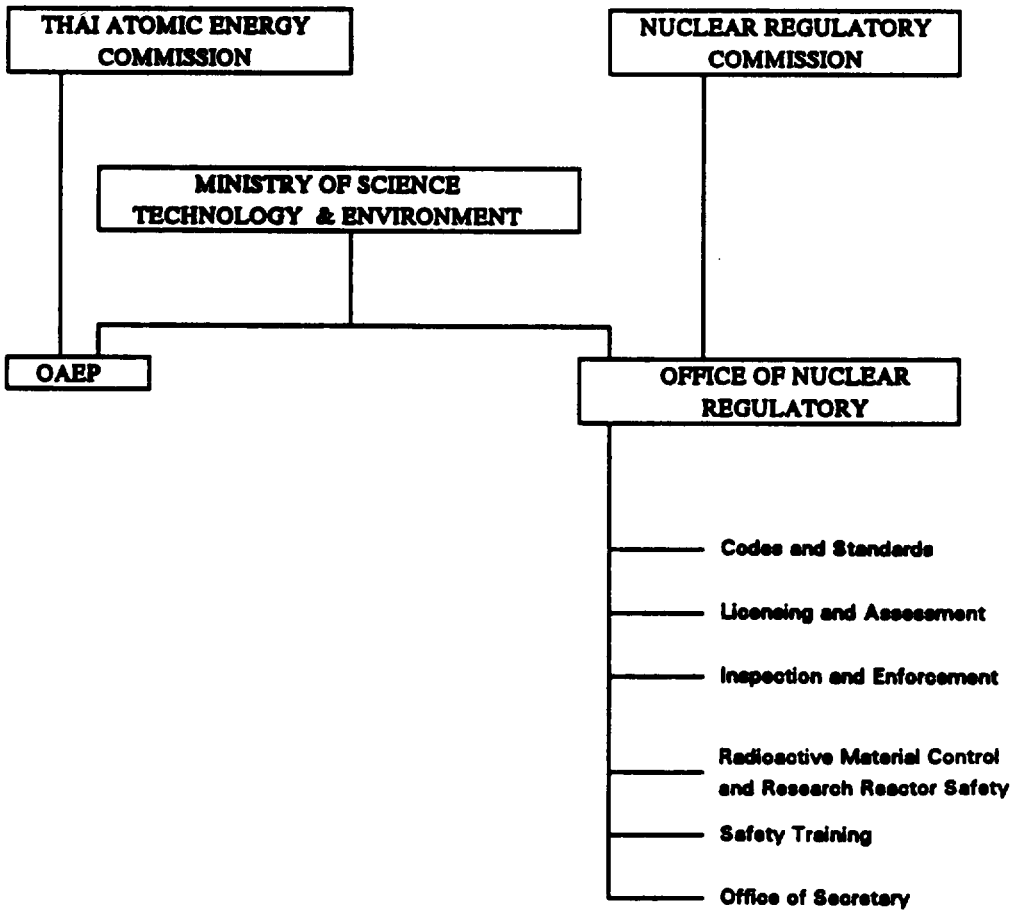
THAILAND
FUEL OPTION STUDY
Nuclear Power Program

Chart 1- CURRENT ORGANIZATION OF OFFICE OF ATOMIC ENERGY FOR PEACE (OAEP)

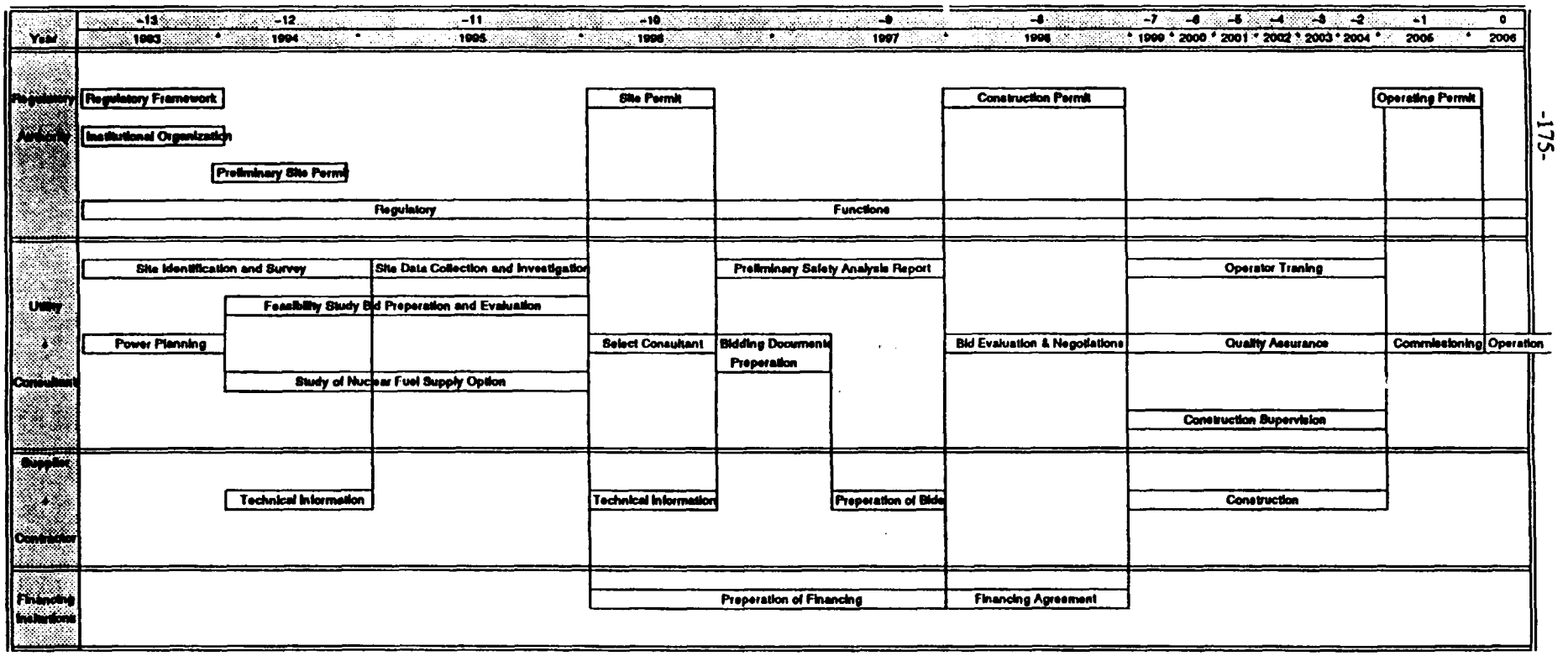


THAILAND
FUEL OPTION STUDY
Nuclear Power Program

Chart 2 - PROPOSED INSTITUTIONAL ORGANIZATION



THAILAND
FUEL OPTION STUDY
Nuclear Power Program
Indication Implementation Schedule for Nuclear Power



THAILAND
FUEL OPTION STUDY
Nuclear Power Program
Table A10.1: Manpower Planning for Regulatory Body

NPP Project	Year	Engineer /a	Scientists /b	Other /c	TOTAL
	12	2	2		4
	11	4-5	2-3		6=8
	10	5-7	3-5		8-12
	09	6-8	4-5	1	11-14
Contract	8	7-10	5-7		12-17
Construction	7	11-12	6-8	2-3	19-23
	6	12-15	10-12		23-30
	5	16-18	12-13	3-5	31-36
	4	18-20	14-15		35-40
Commissioning	3	20-23	15-17		40-45
	2	20-23	15-17		40-45
	1	20-23	15-17		40-45
Commercial Operation	0	20-23	15-17		40-45

Source: Bank Mission.

Note:

/a Engineers (20-23 persons)

- Nuclear
- Electronic/Electrical
- Computer
- Civil
- Mechanical

/b Scientists (15-17 persons)

- Nuclear
- Chemistry
- Physics
- Material Science
- Environmental Science

/c Others (3-5 persons)

- Law
- Business Administration
- Economics
- Library

THAILAND
FUEL OPTION STUDY
Power Expansion Plan (1992-2006)
Table A11.1: EGAT's PDP

Power Plant	Fuel Type	Unit Number	Rating (MW)	Total (MW)	Commissioning Date	
Rayong CC 1 (ST)	-	1	102	102	January	1992
Bang Pakong Thermal	Oil/Gas	3	600	600	January	1992
Bang Pakong CC3 (ST)	-	1	99	99	February	1992
Rayong CC 2 (ST)	-	1	102	102	March	1992
Bang Pakong CC4 (ST)	-	1	99	99	April	1992
Rayong CC 3 (ST)	-	1	102	102	June	1992
Nam Phong CC 1 (ST)	-	1	113	130	September	1992
Rayong CC 4 (GT)	Gas	1-2	103	206	September	1992
Bhumibol Renovation	Hydro	1-2	(70)	(2x70)	Nov 92 - Jul	1993
Bang Pakong Thermal	Oil/Gas	4	600	600	December	1992
Nam Phong CC 2 (GT)	Gas	1-2	121	242	June	1993
South Bankok CC 1 (GT)	Gas	1-2	110	220	August	1993
Rayong CC 4 (ST)	-	1	102	102	September	1993
Khanom CC 1 (GT)	Gas	1-4	112	448	November	1993
Nam Phong CC 2 (ST)	-	1	113	113	May	1994
Pak Mun	Hydro	1-4	34	136	Jun 94 - Nov	1994
South Bangkok CC 1 (ST)	-	1	115	115	August	1994
Khanom CC 1 (ST)	-	1	226	226	September	1994
Sirikit	Hydro	4	125	125	March	1995
Mae Moh	Lignite	12	300	300	May	1995
Mae Moh	Lignite	13	300	300	November	1995
Bhumibol Pumped-Storage	Hydro	8	175	175	December	1995
Kaeng Krung	Hydro	1-2	40	80	December	1996
South Bangkok CC	Gas	2	-	600	Mar 95 - Jan	1997
Wang Noi Gas Turbines	Oil/Gas	-	-	600	March	1996
Mae Kham FBC	Lignite	1	150	150	December	1996
Lower Central CC	Gas	1	600	600	January	1997
EGAT-TNB Stage II Interconnection	-	-	300	300	April	1997
Mae Kham FBC	Lignite	2	150	150	June	1997
Lower Central CC	Gas	2	600	600	July	1997
Lam Takhong Pumped-Storage	Hydro	1-2	250	500	October	1997
Lower Central CC	Gas	3	600	600	March	1998
Ao Phai	Oil/Coal	1	700	700	October	1998
Mae Lama Luang	Hydro	1-2	80	160	February	1999
Ao Phai	Oil/Coal	2	700	700	April	1999
Ao Phai	Oil/Coal	3	700	700	October	1999
New Thermal	Oil/Coal	1	1,000	1,000	April	2000
Mae Taeng	Hydro	1-2	13	26	October	2000
Region 3 CC	Gas	1	300	300	October	2000
New Thermal	Oil/Coal	2	1,000	1,000	April	2001
Lampang	Lignite	1	300	300	November	2001
Lam Takhong Pumped-Storage	Hydro	3-4	250	500	February	2002
Lampang	Lignite	2	300	300	March	2002
Lampang	Lignite	3	300	300	July	2002
Region 3 CC	Gas	2	300	300	October	2002
Lampang	Lignite	4	300	300	November	2002
New Thermal	Oil/Coal	3	1,000	1,000	January	2003
Lampang	Lignite	5	300	300	March	2003
Nam Khek Pumped-Storage	Hydro	1-2	150	300	April	2003
Lampang	Lignite	6	300	300	July	2003
New Thermal	Oil/Coal	4	1,000	1,000	January	2004
New Thermal	Oil/Coal	5	1,000	1,000	July	2004
Lampang	Lignite	7	300	300	January	2005
New Thermal	Oil/Coal	6	1,000	1,000	January	2005
Lampang	Lignite	8	300	300	July	2005
Nuclear Power	Nuclear	1	1,000	1,000	January	2006
Nuclear Power	Nuclear	2	1,000	1,000	July	2006
	Existing Capacity by September 1991		9,610.3	MW		
	Total Added Capacity (up to 2006)		22,791.0	MW		
	Plants Retirement		1,450.1	MW		
	Total Capacity by Year 2006		30,951.2	MW		

Source: EGAT

THAILAND
FUEL OPTION STUDY
Power Expansion Plan (1993-2006)
Table A11.2: Scenario I (Low Gas)

POWER PLANT	FUEL TYPE	UNIT NUMBER	RATING (MW)	TOTAL (MW)	COMMISSIONING DATA	
Khanom CC 1 (GT)	Gas	1-4	112	448	November	1993
Nam Phong CC 2 (ST)	Gas	1	113	113	May	1994
Pak Mun	Hydro	1-4	34	136	June 94	Nov.94
South Bangkok CC 1 (ST)	Gas	1	115	115	August	1994
Khanom CC 1 (ST)	Gas	1	226	226	September	1994
Sirikit	Hydro	4	125	125	March	1995
Mae Moh	Lignite	12	300	300	May	1995
Mae Moh	Lignite	13	300	300	November	1995
Bhumibol Pumped-Storage	Hydro	8	175	175	December	1995
Kaeng Krung	Hydro	1-2	40	80	December	1996
South Bangkok CC2 (GT)	Gas	1	200	400	March	1995
Wang Noi Gas turbine	Diesel	1	600	600	March	1996
Mae Kham FBC Unit 1	Lignite	1	150	150	December	1996
South Bangkok CC2 (ST)	-	1	200	200	February	1997
Lower Central CC 1	Gas	1	600	600	January	1997
EGAT-TNB Stage II Interconnection	-	-	300	300	April	1997
Mae Kham FBC Unit 2	Lignite	2	150	150	June	1997
Lower Central CC 2	Gas	1	600	600	July	1997
Lam Takhong Pumped-Storage	Hydro	1-2	250	500	October	1997
Lower Central CC 3	Gas	1	600	600	March	1998
Region 1 Combined Cycle	Gas	1	600	600	October	1998
Mae Lama Luang	Hydro	1-2	80	180	February	1999
Region 1 Combined Cycle	Gas	2	600	600	April	1999
New Gas Turbine	Diesel	1	200	200	April	1999
Region 1 Combined Cycle	Gas	3	600	600	October	1999
New Thermal	Oil/Coal	1	1,000	1,000	February	2000
New Gas Turbine	Diesel	2	200	200	June	2000
Region 3 Combined Cycle	Gas	1	300	300	October	2000
Mae Taeng	Hydro	1-2	13	26	October	2000
New Thermal	Oil/Coal	2	1,000	1,000	February	2001
Lampang	Lignite	1	300	300	November	2001
Lam Takhong Pumped-Storage	Hydro	3-4	250	500	February	2002
Lampang	Lignite	2	300	300	March	2002
Lampang	Lignite	3	300	300	July	2002
Region 3 Combined Cycle	Gas	2	300	300	October	2002
Lampang	Lignite	4	300	300	November	2002
New Thermal	Oil/Coal	3	1,000	1,000	February	2003
Lampang	Lignite	5	300	300	March	2003
Nam Khek Pumped-Storage	Hydro	1-2	150	300	April	2003
Lampang	Lignite	6	300	300	July	2003
New Thermal	Oil/Coal	4	1,000	1,000	February	2004
New Thermal	Oil/Coal	5	1,000	1,000	June	2004
Lampang	Lignite	7	300	300	November	2004
New Thermal	Oil/Coal	6	1,000	1,000	February	2005
Lampang	Lignite	8	300	300	March	2005
New Thermal	Oil/Coal	7	1,000	1,000	November	2005
New Thermal	Oil/Coal	8	1,000	1,000	March	2006

Existing Capacity by September 1993	12,178.3	MW
Total Added Capacity (Up to 2006)	20,304.0	MW
Plants Retirement	1,431.1	MW
Total Capacity by Year 2006	31,051.2	MW

Source: EGAT.

THAILAND
FUEL OPTION STUDY
Power Expansion Plan (1993-2006)
Table A11.3: Scenario II (High Gas)

Power Plant	Fuel Type	Unit Number	Rating (MW)	Total (MW)	Commissioning Date	
Khanom CC 1 (GT)	Gas	1-4	112	448	November	1993
Nam Phong CC 2 (ST)	Gas	1	113	113	May	1994
Pak Mun	Hydro	1-4	34	136	June 94	Nov 94
South Bangkok CC1 (ST)	Gas	1	115	115	August	1994
Khanom CC 1 (ST)	Gas	1	226	226	September	1994
Sinkit	Hydro	4	125	125	March	1995
Mae Moh	Lignite	12	300	300	May	1995
Mae Moh	Lignite	13	300	300	November	1995
Bhumibol Pumped-Storage	Hydro	8	175	175	December	1995
Kaeng Krung	Hydro	1-2	40	80	December	1996
South Bangkok CC2 (GT)	Gas	1	200	400	March	1995
Wang Noi Gas Turbine	Diesel	1	600	600	March	1996
Mae Kham FBC Unit 1	Lignite	1	150	150	December	1996
South Bangkok CC2 (ST)	-	1	200	200	February	1997
Lower Central CC1	Gas	1	600	600	January	1997
EGAT-TNB Stage II Interconnection	-	*	300	300	April	1997
Mae Kham FBC Unit 2	Lignite	2	150	150	June	1997
Lower Central CC2	Gas	1	600	600	July	1997
Lam Takhong Pumped-Storage	Hydro	1-2	250	500	October	1997
Lower Central CC3	Gas	1	600	600	March	1998
Region 1 Combined Cycle	Gas	1	600	600	October	1998
Mae Lama Luang	Hydro	1-2	80	160	February	1999
Region 1 Combined Cycle	Gas	2	600	600	April	1999
New Gas Turbine	Diesel	1	200	200	April	1999
Region 1 Combined Cycle	Gas	3	600	600	October	1998
Region 1 Combined Cycle	Gas	4	600	600	February	2000
Region 1 Combined Cycle	Gas	5	600	600	June	2000
Region 3 Combined Cycle	Gas	1	300	300	October	2000
Region 1 Combined Cycle	Gas	6	600	600	October	2000
Region 1 Combined Cycle	Gas	7	600	600	February	2001
Region 1 Combined Cycle	Gas	8	600	600	November	2001
Region 1 Combined Cycle	Gas	9	600	600	March	2002
Nam Khek Pumped-Storage	Hydro	1-2	150	300	July	2002
Region 3 Combined Cycle	Gas	2	300	300	October	2002
Region 1 Combined Cycle	Gas	10	600	600	October	2002
Region 1 Combined Cycle	Gas	11	600	600	January	2003
Region 1 Combined Cycle	Gas	12	600	600	April	2003
Region 1 Combined Cycle	Gas	13	600	600	July	2003
Lampang	Lignite	1	300	300	November	2003
Lam Takhong Pumped-Storage	Hydro	3-4	250	500	February	2004
Lampang	Lignite	2	300	300	March	2004
New Gas Turbine	Diesel	2	200	200	June	2004
Lampang	Lignite	3	300	300	July	2004
Region 1 Combined Cycle	Gas	14	600	600	October	2004
Lampang	Lignite	4	300	300	November	2004
New Thermal	Oil/Coal	1	1000	1000	February	2005
Lampang	Lignite	5	300	300	March	2005
Lampang	Litnite	6	300	300	November	2005
Lampang	Lignite	7	300	300	March	2006
Lampang	Lignite	8	300	300	July	2006
New Gas Turbine	Diesel	3	200	200	July	2006
	Existing Capacity by September 1993		12,178.3	MW		
	Total Added Capacity (up to 2006)		20,078.0	MW		
	Plants Retirement		1,431.1	MW		
	Total Capacity by year 2006		30,825.2	MW		

Source: EGAT

THAILAND
FUEL OPTION STUDY
Power Expansion Plan (1993-2006)
Table A11.4: Scenario III (LNG)

POWER PLANT	FUEL TYPE	UNIT NUMBER	RATING (MW)	TOTAL (MW)	COMMISSIONING DATA	
Khanom CC 1 (GT)	Gas	1-4	112	448	November	1993
Nam Phong CC 2 (ST)	Gas	1	113	113	May	1994
Pak Mun	Hydro	1-4	34	136	June 94	Nov.94
South Bangkok CC 1 (ST)	Gas	1	115	115	August	1994
Khanom CC 1 (ST)	Gas	1	226	226	September	1994
Sirikit	Hydro	4	125	125	March	1995
Mae Moh	Lignite	12	300	300	May	1995
Mae Moh	Lignite	13	300	300	November	1995
Bhumibol Pumped-Storage	Hydro	8	175	175	December	1995
Kaeng Krung	Hydro	1-2	40	80	December	1996
South Bangkok CC2 (GT)	Gas	1	200	400	March	1995
Wang Noi Gas Turbine	Diesel	1	600	600	March	1996
Mae Kham FBC Unit 1	Lignite	1	150	150	December	1996
South Bangkok CC2 (ST)	-	1	200	200	February	1997
Lower Central CC 1	Gas	1	600	600	January	1997
EGAT-TNB Stage II Interconnection	-	-	300	300	April	1997
Mae Kham FBC Unit 2	Lignite	2	150	150	June	1997
Lower Central CC 2	Gas	1	600	600	July	1997
Lam Takhong Pumped-Storage	Hydro	1-2	250	500	October	1997
Lower Central CC 3	Gas	1	600	600	March	1998
Region 1 Combined Cycle	Gas	1	600	600	October	1998
Mae Lama Luang	Hydro	1-2	80	160	February	2000
Region 1 Combined Cycle	Gas	2	600	600	April	1999
New Gas Turbine	Diesel	1	200	200	April	1999
Region 1 Combined Cycle	Gas	3	600	600	October	1999
Region 1 Combined Cycle	Gas	4	600	600	February	1999
Region 1 Combined Cycle	Gas	5	600	600	June	2000
Region 3 Combined Cycle	Gas	1	300	300	October	2000
Region 1 Combined Cycle	Gas	6	600	600	October	2000
Region 1 Combined Cycle	Gas	7	600	600	February	2001
Lampang	Lignite	1	300	300	November	2001
Region 1 Combined Cycle	Gas	8	600	600	February	2002
Lampang	Lignite	2	300	300	March	2002
Lampang	Lignite	3	300	300	July	2002
Region 3 Combined Cycle	Gas	2	300	300	October	2002
Lampang	Lignite	4	300	300	November	2002
New Thermal	Oil/Coal	1	1,000	1,000	February	2003
Lampang	Lignite	5	300	300	March	2003
Lam Takhong Pumped-Storage	Hydro	3-4	250	500	April	2003
Lampang	Lignite	6	300	300	July	2003
Lampang	Lignite	7	300	300	November	2003
Region 1 Combined Cycle	Gas	9	600	600	February	2004
Region 1 Combined Cycle	Gas	10	600	600	June	2004
Lampang	Lignite	2	300	300	July	2004
Region 1 Combined Cycle	Gas	11	600	600	October	2004
Region 1 Combined Cycle	Gas	12	600	600	February	2005
Nam Khek Pumped-Storage	Hydro	1-2	150	300	March	2005
Region 1 Combined Cycle	Gas	13	600	600	June	2005
New Thermal	Oil/Coal	2	1,000	1,000	November	2005

Existing Capacity by September 1993	=	12,178.3	MW
Total Added Capacity (Up to 2006)	=	20,078.0	MW
Plants Retirement	=	1,431.1	MW
Total Capacity by Year 2006	=	30,825.2	MW

Source: EGAT.

THAILAND
FUEL OPTION STUDY
Table 12.1: Assumptions for the Comparative Analysis of Power Generation Costs

Plant	Capacity (MW)	Unit Investment Cost ($/kW)	O&M Cost (% of Inv. Cost)	Fuel	Heat Content (BTU/unit)	Fuel Cost ($/unit)	Thermal Efficiency (%)	Implementation Period (Yrs)	Economic Life (Yrs)	Decommissioning Cost ($/Kw)
Base Load Generation:										
Combined Cycle	600	650	4.0	Nat. Gas	10^6/MCF	2.45/MCF	44	3	20	n.a.
	"	"	"	LNG	"	4.13/MCF	"	"	"	"
Lampang	600	956	4.0	Lignite	11.9×10^6/ton	14.5/ton	34.5	5	25	n.a.
with fgd.	600	1252	4.0	Lignite	11.9×10^6/ton	14.5/ton	33	5	25	n.a.
Ao Phai	1,400	999	3.8	Coal	26.4×10^6/ton	54/ton	36	5	25	n.a.
New Thermal	2,000	1,076	3.7	Coal	26.4×10^6/ton	54/ton	38	5	25	n.a.
	"	900	2.7	Fuel Oil	5.9×10^6/Bbl	21.2/Bbl	39	4	"	"
Nuclear										
1st unit	1,000	1,590-3,200	2.5	Nuclear	n.a.	0.9¢/kWh		8	25	205
2nd unit	1,000	1,272-2,500	2.5	Nuclear	n.a.	0.9¢/kWh		8	25	205
Nam Theun 2	600	976	1.0	Hydro	n.a.	n.a.	n.a.	7	50	n.a.
Nam Theun 1/2	210	1,616	1.0	Hydro	n.a.	n.a.	n.a.	4	50	n.a.
Mae Lama Luang	160	1,158	1.0	Hydro	n.a.	n.a.	n.a.	5	50	n.a.
Mae Taeng	26	1,612	1.0	Hydro	n.a.	n.a.	n.a.	3	50	n.a.
Peak Load Generation:										
Gas Turbines	100	450-500	7.0	Nat. Gas	10^6/MCF	2.45/MCF	29	2	15	n.a.
	"	"	7.0	LNG	"	4.13/MCF	"	"	"	"
	"	"	8.0	Diesel	5.74×10^6/Bbl	26.8/Bbl	"	"	"	"
Lam Takhong (pumped-storage)										
Phase I	500	722	1.0	Hydro	n.a.	3¢/kWh	n.a.	5	25	n.a.
Phase II	500	271	1.0	Hydro	n.a.	"	n.a.	4	25	n.a.
Nam Khek (pumped-storage)	300	533	1.0	Hydro	n.a.	"	n.a.	5	25	n.a.

Discount Rate: base 10%, sensitivity range 6-16%
Source: Bank Mission Estimate

THAILAND

FUEL OPTION STUDY

Environmental Tables

Appendix Table A13.1 - SO_2 Emissions by Fuel, 1982-1991								
	1982		1985		1990		1991	
Natural gas	2	0.0%	5	0.0%	9	0.0%	11	0.0%
Fuel Oil	170816	62.1%	130007	36.6%	302922	37.7%	348937	37.7%
Diesel	17914	6.5%	23343	6.6%	42345	5.3%	41715	4.5%
Gasoline	3930	1.4%	4075	1.1%	7188	0.9%	7600	0.8%
Lignite	72706	26.4%	186619	52.5%	438994	54.7%	514620	55.6%
Coal (Import)	1552	0.6%	3242	0.9%	2892	0.4%	3988	0.4%
Biomass fuels	7990	2.9%	8143	2.3%	8651	1.1%	8942	1.0%
	274910	100.0%	355434	100.0%	803001	100.0%	925813	100.0%

Appendix Table A13.2 - NOx Emissions by Fuel, 1982-1991								
	1982		1985		1990		1991	
Natural gas	5694	2.8%	12416	4.6%	21602	4.5%	27749	5.4%
Fuel Oil	21911	10.7%	16304	6.1%	38619	8.1%	44832	8.8%
Diesel	103548	50.5%	148543	55.4%	263173	55.1%	268984	52.7%
Gasoline	28413	13.9%	29467	11.0%	51975	10.9%	54957	10.8%
Lignite	10298	5.0%	23738	8.9%	65320	13.7%	75070	14.7%
Coal (M)	1634	0.8%	3412	1.3%	3044	0.6%	4197	0.8%
Biomass fuels	33454	16.3%	34315	12.8%	34237	7.2%	34755	6.8%
	204953	100.0%	268195	100.0%	477971	100.0%	510545	100.0%

Source: Bank Mission Estimate.

Appendix Table A13.3 - SO_2 Emissions by Sector, 1982-1991								
	1982		1985		1990		1991	
	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)
Utility	150546	54.8%	223610	62.9%	517436	64.4%	621130	67.1%
Industry	88822	32.3%	90874	25.6%	207360	25.8%	222570	24.0%
Transport	22523	8.2%	27379	7.7%	61311	7.6%	64807	7.0%
Agriculture	4855	1.8%	5803	1.6%	7781	1.0%	7882	0.9%
Other	8164	3.0%	7768	2.2%	9112	1.1%	9425	1.0%
Total	274910	100.0%	355434	100.0%	803001	100.0%	925813	100.0%

Appendix Table A13.4 - NOx Emissions by Sector, 1982-1991								
	1982		1985		1990		1991	
	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)
Utility	24729	12.1%	37429	14.0%	81110	17.0%	99013	19.4%
Industry	21932	10.7%	25596	9.5%	54778	11.5%	60125	11.8%
Transport	89818	43.8%	129697	48.4%	253466	53.0%	260676	51.1%
Agriculture	36008	17.6%	43037	16.0%	57720	12.1%	58469	11.5%
Other	32467	15.8%	32435	12.1%	30897	6.5%	32262	6.3%
Total	204953	100.0%	268195	100.0%	477971	100.0%	510545	100.0%

Appendix Table A13.5 - TSP Emissions by Sector, 1982-1991								
	1982		1985		1990		1991	
	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)
Utility	5316	1.7%	13945	3.8%	30057	5.3%	35712	5.8%
Industry	116725	36.6%	136599	37.6%	282128	49.4%	311019	50.9%
Transport	48656	15.3%	59053	16.3%	110712	19.4%	115526	18.9%
Agriculture	8885	2.8%	10594	2.9%	13910	2.4%	14017	2.3%
Other	139341	43.7%	142841	39.3%	134421	23.5%	134259	22.0%
Total	318924	100.0%	363031	100.0%	571228	100.0%	610533	100.0%

Source: Bank Mission Estimate.

Appendix Table A13.6 - SO_2 Emissions by Fuel: PDP Scenario						
	1990	1995	2000	2005	2010	2010
	(t)	(t)	(t)	(t)	(t)	%
Natural gas	9	13	20	18	18	0.0%
Fuel Oil	100974	199639	233792	254940	402542	16.4%
Diesel	42345	59590	95476	127037	163228	6.7%
Gasoline	7188	10694	16399	23351	32657	1.3%
Lignite	438994	592483	812690	1328315	1529407	62.4%
Coal (Import)	2892	9320	75369	207860	311423	12.7%
Biomass fuels	8651	9491	10224	10378	10378	0.4%
Total	601052	881229	1243968	1951898	2449652	100.0%

Appendix Table A13.7 - NOx Emissions by Fuel: PDP Scenario						
	1990	1995	2000	2005	2010	2010
	(t)	(t)	(t)	(t)	(t)	%
Natural gas	21602	31857	46194	40836	39741	1.9%
Fuel Oil	38619	78067	88916	94777	153653	7.5%
Diesel	263173	381135	592946	799051	1041900	51.1%
Gasoline	51975	77323	118574	168845	236137	11.6%
Lignite	65320	91942	130680	213156	274860	13.5%
Coal (Import)	3044	9810	62163	167248	251965	12.4%
Biomass fuels	34237	36888	39739	40335	40335	2.0%
Total	477971	707023	1079212	1524247	2038591	100.0%

Source: Bank Mission Estimate.

Appendix Table A13.8 - SO_2 Emissions by Fuel: Scenario II (HiGas)						
	1990	1995	2000	2005	2010	2010
	(t)	(t)	(t)	(t)	(t)	%
Natural gas	9	15	31	29	29	0.0%
Fuel Oil	100974	181076	238884	280476	416374	16.8%
Diesel	42345	59590	96343	127904	164095	6.6%
Gasoline	7188	10694	16399	23351	32657	1.3%
Lignite	438994	592483	812690	1328315	1529407	61.6%
Coal (Import)	2892	8284	14773	135720	330338	13.3%
Biomass fuels	8651	9491	10224	10378	10378	0.4%
Total	601052	861633	1189342	1906172	2483277	100.0%

Appendix Table A13.9 - NOx Emissions by Fuel: Scenario II (HiGas)						
	1990	1995	2000	2005	2010	2010
	(t)	(t)	(t)	(t)	(t)	%
Natural gas	21602	36894	75102	69219	67773	3.2%
Fuel Oil	38619	70251	91060	105529	159477	7.6%
Diesel	263173	381135	593140	799245	1042094	49.9%
Gasoline	51975	77323	118574	168845	236137	11.3%
Lignite	65320	91942	130680	213156	274860	13.2%
Coal (M)	3044	8720	15550	111755	266515	12.8%
Biomass fuels	34237	36888	39739	40335	40335	1.9%
Total	477971	703154	1063845	1508083	2087191	100.0%

Source: Bank Mission Estimate.

Appendix Table A13.10 - SO_2 Emissions by Fuel: Scenario I (LoGas)						
	1990	1995	2000	2005	2010	2010
	(t)	(t)	(t)	(t)	(t)	%
Natural gas	9	15	19	16	15	0.0%
Fuel Oil	100974	181076	249733	272705	442119	16.2%
Diesel	42345	59590	105030	136591	172782	6.3%
Gasoline	7188	10694	16399	23351	32657	1.2%
Lignite	438994	592483	812690	1490727	1691819	62.2%
Coal (Import)	2892	8284	75939	211508	371166	13.6%
Biomass fuels	8651	9491	10224	10799	11350	0.4%
Total	601052	861633	1270033	2145697	2721909	100.0%

Appendix Table A13.11 - NOx Emissions by Fuel: Scenario I (LoGas)						
	1990	1995	2000	2005	2010	2010
	(t)	(t)	(t)	(t)	(t)	%
Natural gas	21602	36894	45844	37303	35858	1.7%
Fuel Oil	38619	70251	95628	102257	170317	8.0%
Diesel	263173	381135	595081	801187	1044036	49.2%
Gasoline	51975	77323	118574	168845	236137	11.1%
Lignite	65320	91942	130680	230480	292184	13.8%
Coal (M)	3044	8720	62763	171088	299130	14.1%
Biomass fuels	34237	36888	39739	41972	44113	2.1%
Total	477971	703154	1088309	1553132	2121775	100.0%

Source: Bank Mission Estimate.

Appendix Table A13.12 - SO_2 Emissions by Sector: PDP Scenario										
	1990		1995		2000		2005		2010	
	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)
Utility	517436	64.4%	842088	65.8%	1027064	60.0%	1501481	61.0%	1948379	59.9%
Industry	207360	25.8%	324940	25.4%	512905	30.0%	728838	29.6%	1001994	30.8%
Transp.	61311	7.6%	92921	7.3%	145857	8.5%	202379	8.2%	272309	8.4%
Agri.	7781	1.0%	10140	0.8%	13893	0.8%	16332	0.7%	18478	0.6%
Other	9112	1.1%	10418	0.8%	11833	0.7%	12748	0.5%	13576	0.4%
Total	803001	100.0 %	1280507	100.0 %	1711551	100.0 %	2461777	100.0 %	3254736	100.0 %

Appendix Table A13.13 - NOx Emissions by Sector: PDP Scenario										
	1990		1995		2000		2005		2010	
	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)
Utility	81110	17.0%	131195	18.6%	201318	18.7%	322246	21.1%	436050	21.4%
Industry	54778	11.5%	87518	12.4%	133434	12.4%	198697	13.0%	286306	14.0%
Transport	253466	53.0%	378657	53.6%	604037	56.0%	843410	55.3%	1139377	55.9%
Agriculture	57720	12.1%	75218	10.6%	103055	9.5%	121148	7.9%	137068	6.7%
Other	30897	6.5%	34435	4.9%	37367	3.5%	38747	2.5%	39790	2.0%
Total	477971	100.0 %	707023	100.0 %	1079212	100.0 %	1524247	100.0 %	2038591	100.0%

Appendix Table A13.14 - TSP Emissions by Sector: PDP Scenario										
	1990		1995		2000		2005		2010	
	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)
Utility	30057	5.3%	39904	5.0%	70280	6.3%	138026	8.7%	167671	7.6%
Industry	282128	49.4%	424439	53.7%	600022	54.2%	903397	56.7%	1351232	61.1%
Transport	110712	19.4%	165462	20.9%	259371	23.4%	366105	23.0%	503596	22.8%
Agriculture	13910	2.4%	18033	2.3%	24706	2.2%	29044	1.8%	32861	1.5%
Other	134421	23.5%	142561	18.0%	153668	13.9%	156221	9.8%	156535	7.1%
Total	571228	100.0 %	790400	100.0 %	1108048	100.0 %	1592793	100.0 %	2211894	100.0%

Source: Bank Mission Estimate.

Appendix Table A13.15 - SO_2 Emissions by Sector: Scenario II (HiGas)										
	1990		1995		2000		2005		2010	
	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)
Utility	517436	64.4%	786401	64.3%	982622	58.9%	1506827	61.1%	2009668	60.6%
Industry	207360	25.8%	323905	26.5%	512905	30.8%	728838	29.5%	1001994	30.2%
Transport	61311	7.6%	92921	7.6%	145857	8.7%	202379	8.2%	272309	8.2%
Agriculture	7781	1.0%	10140	0.8%	13893	0.8%	16332	0.7%	18478	0.6%
Other	9112	1.1%	10418	0.9%	11833	0.7%	12748	0.5%	13576	0.4%
Total	803001	100.0 %	1223784	100.0 %	1667110	100.0 %	2467123	100.0 %	3316025	100.0%

Appendix Table A13.16 - NOx Emissions by Sector: Scenario II (HiGas)										
	1990		1995		2000		2005		2010	
	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)
Utility	81110	17.0%	128416	18.3%	185951	17.5%	306081	20.3%	484650	23.2%
Industry	54778	11.5%	86428	12.3%	133434	12.5%	198697	13.2%	286306	13.7%
Transport	253466	53.0%	378657	53.9%	604037	56.8%	843410	55.9%	1139377	54.6%
Agriculture	57720	12.1%	75218	10.7%	103055	9.7%	121148	8.0%	137068	6.6%
Other	30897	6.5%	34435	4.9%	37367	3.5%	38747	2.6%	39790	1.9%
Total	477971	100.0 %	703154	100.0 %	1063845	100.0 %	1508083	100.0 %	2087191	100.0%

Appendix Table A13.17 - TSP Emissions by Sector: Scenario II (HiGas)										
	1990		1995		2000		2005		2010	
	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)
Utility	30057	5.3%	39745	5.1%	52938	4.9%	117546	7.5%	173238	7.8%
Industry	282128	49.4%	418335	53.3%	600022	55.0%	903397	57.5%	1351232	60.9%
Transport	110712	19.4%	165462	21.1%	259371	23.8%	366105	23.3%	503596	22.7%
Agriculture	13910	2.4%	18033	2.3%	24706	2.3%	29044	1.8%	32861	1.5%
Other	134421	23.5%	142561	18.2%	153668	14.1%	156221	9.9%	156535	7.1%
Total	571228	100.0 %	784137	100.0 %	1090706	100.0 %	1572313	100.0 %	2217462	100.0%

Source: Bank Mission Estimate.

Appendix Table A13.18 - SO_2 Emissions by Sector: Scenario I (LoGas)										
	1990		1995		2000		2005		2010	
	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)
Utility	517436	64.4%	786401	64.3%	1084441	61.3%	1726742	64.2%	2294554	63.6%
Industry	207360	25.8%	323905	26.5%	513474	29.0%	732710	27.2%	1006781	27.9%
Transport	61311	7.6%	92921	7.6%	145857	8.2%	202379	7.5%	272309	7.6%
Agriculture	7781	1.0%	10140	0.8%	13893	0.8%	16332	0.6%	18478	0.5%
Other	9112	1.1%	10418	0.9%	11833	0.7%	12942	0.5%	14025	0.4%
Total	803001	100.0 %	1223784	100.0 %	1769498	100.0 %	2691106	100.0 %	3606146	100.0%

Appendix Table A13.19 - NOx Emissions by Sector: Scenario I (LoGas)										
	1990		1995		2000		2005		2010	
	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)
Utility	81110	17.0%	128416	18.3%	210604	19.4%	349098	22.5%	514411	24.2%
Industry	54778	11.5%	86428	12.3%	133245	12.2%	199563	12.8%	288438	13.6%
Transport	253466	53.0%	378657	53.9%	604037	55.5%	843410	54.3%	1139377	53.7%
Agriculture	57720	12.1%	75218	10.7%	103055	9.5%	121148	7.8%	137068	6.5%
Other	30897	6.5%	34435	4.9%	37367	3.4%	39913	2.6%	42481	2.0%
Total	477971	100.0 %	703154	100.0 %	1088309	100.0 %	1553132	100.0 %	2121775	100.0%

Appendix Table A13.20 - TSP Emissions by Sector: Scenario I (LoGas)										
	1990		1995		2000		2005		2010	
	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)	(t)	(%)
Utility	30057	5.3%	39745	5.1%	70431	6.3%	151184	9.2%	196951	8.6%
Industry	282128	49.4%	418335	53.3%	603367	54.3%	930077	56.8%	1388404	60.6%
Transport	110712	19.4%	165462	21.1%	259371	23.3%	366105	22.3%	503596	22.0%
Agriculture	13910	2.4%	18033	2.3%	24706	2.2%	29044	1.8%	32861	1.4%
Other	134421	23.5%	142561	18.2%	153668	13.8%	162442	9.9%	170888	7.5%
Total	571228	100.0 %	784137	100.0 %	1111544	100.0 %	1638853	100.0 %	2292700	100.0%

Source: Bank Mission Estimate.

Appendix Table A13.21 - Alternative SO_2 Control Scenarios
Sectoral Emissions - PDP Scenario with FGD
(Tons)

SO_2	1990	1995	2000	2005	2010
Utility	517,436	738,748	846,880	891,908	1,309,213
Industry	207,360	324,940	512,905	728,838	1,001,994
Transport	61,311	92,921	145,857	202,379	272,309
Agriculture	7,781	10,140	13,893	16,332	18,478
Other	9,112	10,418	11,833	12,748	13,576
Total	803,001	1,177,166	1,531,367	1,852,204	2,615,570
SECTORAL EMISSIONS - SCENARIO II WITH FGD					
Utility	517,436	683,061	904,257	1,024,026	1,562,245
Industry	207,360	323,905	513,474	732,710	1,006,781
Transport	61,311	92,921	145,857	202,379	272,309
Agriculture	7,781	10,140	13,893	16,332	18,478
Other	9,112	10,418	11,833	12,942	14,025
Total	803,001	1,120,444	1,589,314	1,988,389	2,873,837
SECTORAL EMISSIONS - SCENARIO I WITH FGD					
Utility	517,436	683,061	802,438	897,254	1,370,503
Industry	207,360	323,905	512,905	728,838	1,001,994
Transport	61,311	92,921	145,857	202,379	272,309
Agriculture	7,781	10,140	13,893	16,332	18,478
Other	9,112	10,418	11,833	12,748	13,576
Total	803,001	1,120,444	1,486,926	1,857,550	2,676,859

Source: Bank Mission Estimate.

THAILAND
FUEL OPTION STUDY

Table A14.1: Capital Expenditures (Million Bahts)

YEAR	GOVERNMENT (A) 1/	STATE CORPORATION (B) 1/	TOTAL PUBLIC INVESTMENT (C) 1/	POWER SECTOR				PETROLEUM
				EGAT (D) 2/	MEA (E) 2/	PEA (F) 2/	TOTAL (G)	PTT (H) 2/
1983	36,000	30,600	66,600	14,194	737	3,015	17,946	1,784
1984	34,400	33,000	67,400	9,780	839	3,584	14,203	4,590
1985	41,600	35,700	77,300	7,287	823	3,660	11,770	3,516
1986	40,100	35,400	75,500	7,469	1,190	3,809	12,468	672
1987	37,200	31,000	68,200	5,250	1,481	3,471	10,202	697
1988	37,700	42,900	80,600	7,200	1,772	3,817	12,789	1,035
1989	46,600	47,700	94,300	11,093	2,063	4,164	17,320	1,373
1990	53,347	72,000	125,347	26,600	2,961	4,906	34,467	2,800
1991	58,071	97,000	155,071	30,426	3,859	5,548	39,833	1,337

Source: Debt and Intenational Finance Division, International Economics Department, World Bank.

1/ Figures for 1983-1989 were obtained from "Thailand: Country Economic Memorandum, Building on the Recent Success - A Policy Framework", Volume I, World Bank, 1989. Figures for 1990 and 1991 were obtained from the 1991 Annual Economic Report of the Bank of Thailand (they represent "Invstment budget").

2/ Figures for 1983-1986 were obtained from "Thailand: Country Economic Memorandum, Building on the Recent Success - A Policy Framework", Volume II: Statistical Annex, World Bank, 1989. Figures for 1987-1991 were obtained from the annual reports of the state corporations.

Note: As a rsult of unavailability of data in the annual reports, the following figures were inter/extrapolated:
(E) 1987, 1988, 1991; (F) 1988, 1991; (H) 1988.

THAILAND
FUEL OPTION STUDY

Table A14.2: Investment Ratios for EGAT, MEA, PEA and PTT

YEAR	POWER SECTOR								PETROLEUM SECTOR	
	EGAT/STATE CORPORATION	EGAT/TOTAL INVESTMENT	MEA/STATE CORPORATION	MEA/TOTAL INVESTMENT	PEA/STATE CORPORATION	PEA/TOTAL INVESTMENT	TOTAL/STATE CORPORATION	TOTAL/TOTAL INVESTMENT	PTT/STATE CORPORATION	PTT/TOTAL INVESTMENT
1983	0.46	0.21	0.02	0.01	0.10	0.05	0.59	0.27	0.06	0.03
1984	0.30	0.15	0.10	0.13	0.11	0.05	0.43	0.21	0.14	0.07
1985	0.20	0.09	0.09	0.08	0.10	0.05	0.33	0.15	0.10	0.05
1986	0.21	0.10	0.09	0.02	0.11	0.05	0.35	0.17	0.02	0.01
1987	0.17	0.08	0.09	0.02	0.11	0.05	0.33	0.15	0.02	0.01
1988	0.17	0.09	0.10	0.03	0.09	0.05	0.30	0.16	0.02	0.01
1989	0.23	0.12	0.09	0.03	0.09	0.04	0.36	0.18	0.03	0.01
1990	0.37	0.21	0.09	0.05	0.07	0.04	0.48	0.27	0.04	0.02
1991	0.31	0.20	0.10	0.02	0.06	0.04	0.41	0.26	0.01	0.01

Source: Debt and International Finance Division, International Economics Department, World Bank.

Table A14.3: Outstanding Debt Ratios for EGAT, MEA, PEA and PTT

YEAR	POWER SECTOR								PETROLEUM SECTOR	
	EGAT/TOTAL PUBLIC DEBT	EGAT/STATE COPRORATION	MEA/TOTAL PUBLIC DEBT	MEA/STATE COPRORATION	PEA/TOTAL PUBLIC DEBT	PEA/STATE COPRORATION	POWER/TOTAL PUBLIC DEBT	POWER/STATE COPRORATION	PTT/TOTAL PUBLIC DEBT	PTT/STATE COPRORATION
1981	0.24	0.40	0.01	0.02	0.04	0.06	0.29	0.48	0.14	0.09
1982	0.22	0.36	0.01	0.02	0.03	0.05	0.26	0.43	0.14	0.14
1983	0.21	0.35	0.01	0.01	0.03	0.06	0.25	0.42	0.12	0.13
1984	0.21	0.36	0.01	0.01	0.03	0.06	0.25	0.43	0.10	0.12
1985	0.19	0.32	0.01	0.01	0.04	0.06	0.23	0.39	0.10	0.13
1986	0.17	0.30	0.00	0.01	0.04	0.07	0.22	0.38	0.09	0.12
1987	0.17	0.29	0.00	0.01	0.05	0.08	0.22	0.38	0.06	0.09
1988	0.18	0.30	0.00	0.01	0.05	0.08	0.23	0.39	0.04	0.06
1989	0.19	0.33	0.00	0.01	0.05	0.08	0.23	0.42	0.04	0.06
1990	0.21	0.34	0.00	0.01	0.05	0.09	0.26	0.43	0.04	0.05
1991	0.19	0.30	0.00	0.01	0.06	0.10	0.25	0.40	0.04	0.05

Source: Debt and International Finance Division, International Economics Department, World Bank.

THAILAND
FUEL OPTION STUDY

Table A14.4: Outstanding Debt (Thousands of U.S. Dollars)

YEAR	TOTAL PUBLIC DEBT (A)	STATE CORPORATIONS (B)	CENTRAL GOVERNMENT (C)	POWER SECTOR DEBT				PETROLEUM SECTOR DEBT
				EGAT (1)	MEA (2)	PEA (3)	TOTAL (4)	PTT (5)
1981	$5,017,006	$3,159,683	$1,857,323	$1,961,992	$91,461	$303,824	$2,357,277	$434,372
1982	$6,033,754	$3,870,902	$2,162,852	$2,114,789	$90,116	$310,510	$2,515,415	$821,949
1983	$6,901,743	$4,401,557	$2,500,186	$2,118,105	$87,380	$337,826	$2,543,311	$810,667
1984	$7,186,415	$4,512,814	$2,673,601	$2,161,808	$81,034	$337,923	$2,580,765	$713,113
1985	$9,860,357	$5,828,546	$4,031,811	$2,437,041	$75,552	$497,722	$3,010,315	$992,610
1986	$11,487,924	$6,686,331	$4,801,593	$2,582,679	$69,080	$607,847	$3,259,606	$1,048,256
1987	$13,831,776	$7,715,027	$6,116,749	$2,894,280	$62,617	$812,622	$3,769,519	$854,765
1988	$13,185,993	$7,184,574	$6,001,419	$2,949,069	$56,745	$807,922	$3,813,736	$566,107
1989	$12,407,811	$6,805,394	$5,602,417	$2,871,203	$50,401	$698,934	$3,620,538	$478,100
1990	$12,573,417	$7,933,570	$4,639,847	$3,295,065	$62,555	$846,743	$4,204,363	$486,726
1991	$13,268,660	$8,345,066	$4,923,594	$3,058,610	$54,648	$966,443	$4,079,701	$484,844

Source: Debt and Intenational Finance Division, International Economics Department, World Bank.

Note: Debt figures correspond to disbursed amounts

CHARTS

THAILAND
FUEL OPTION STUDY
Agencies Related to Energy

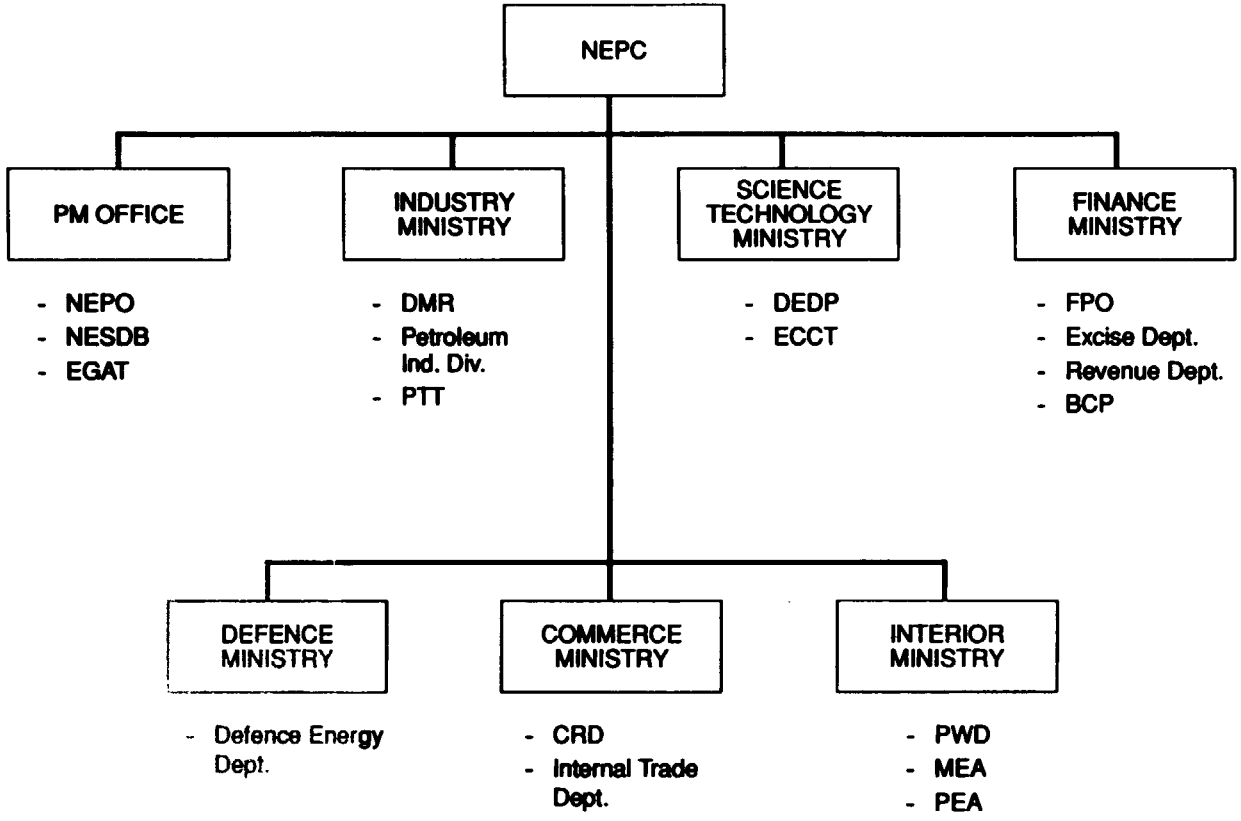


Chart 3

THAILAND
FUEL OPTION STUDY
National Energy Policy Council

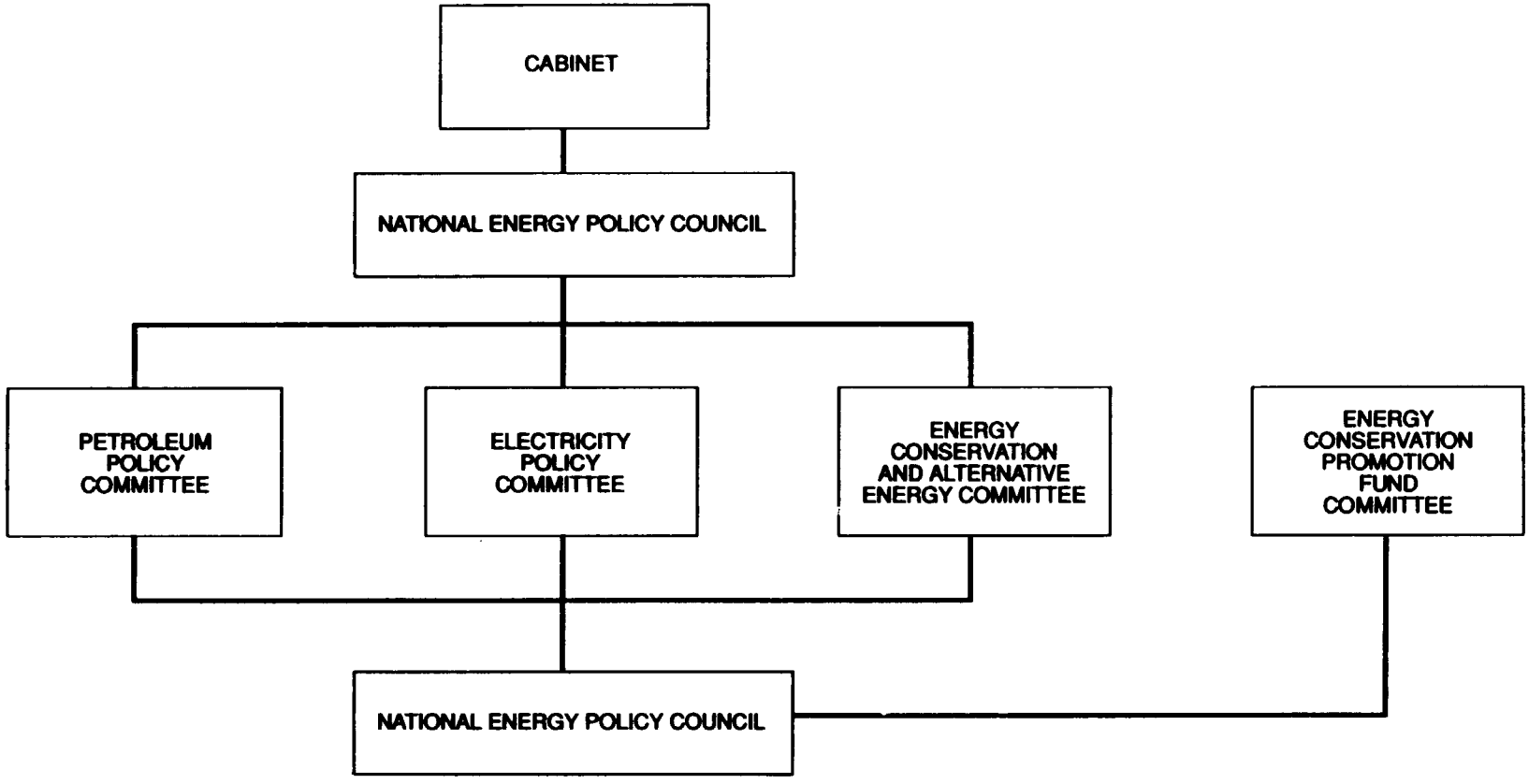


Chart 4

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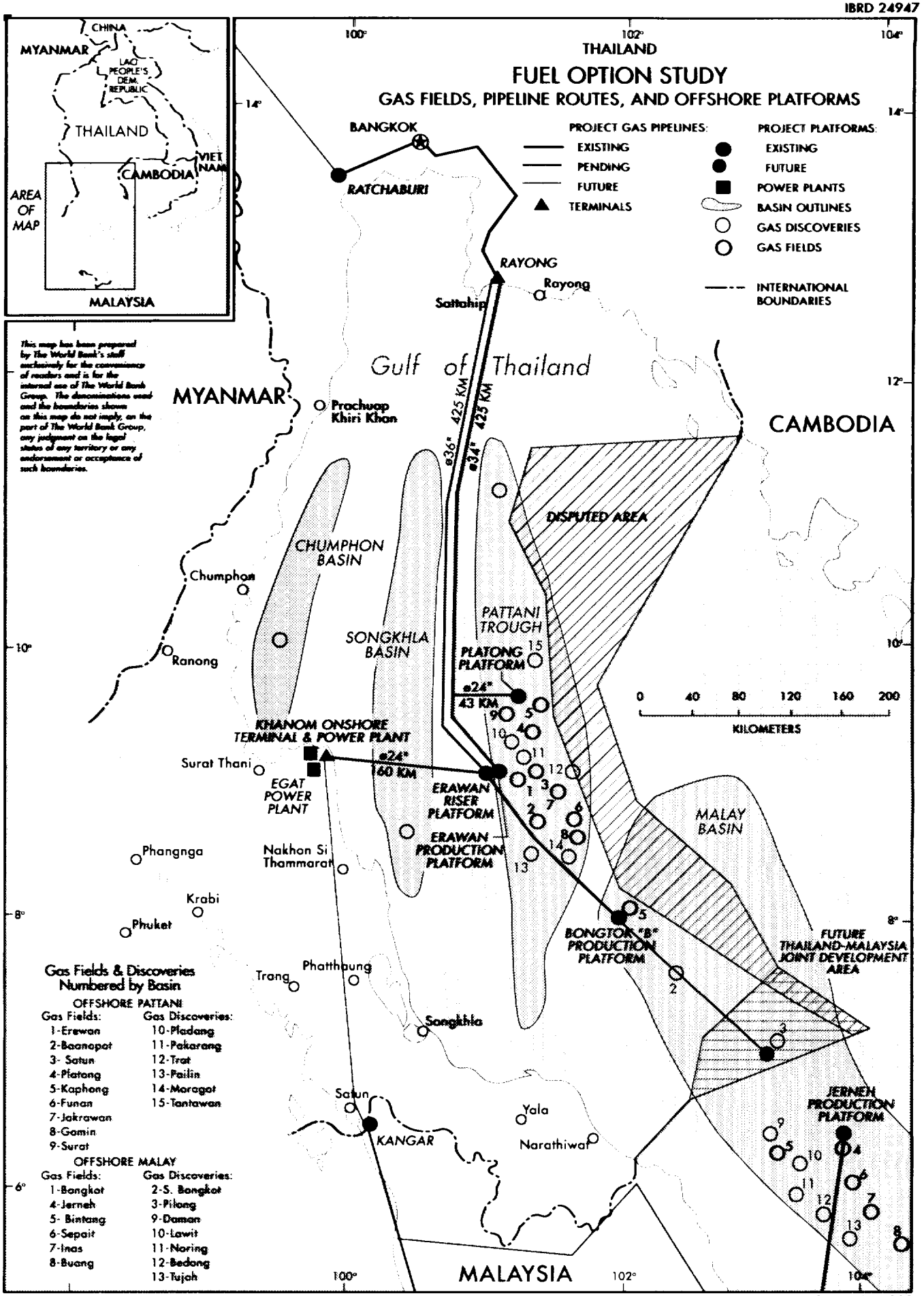

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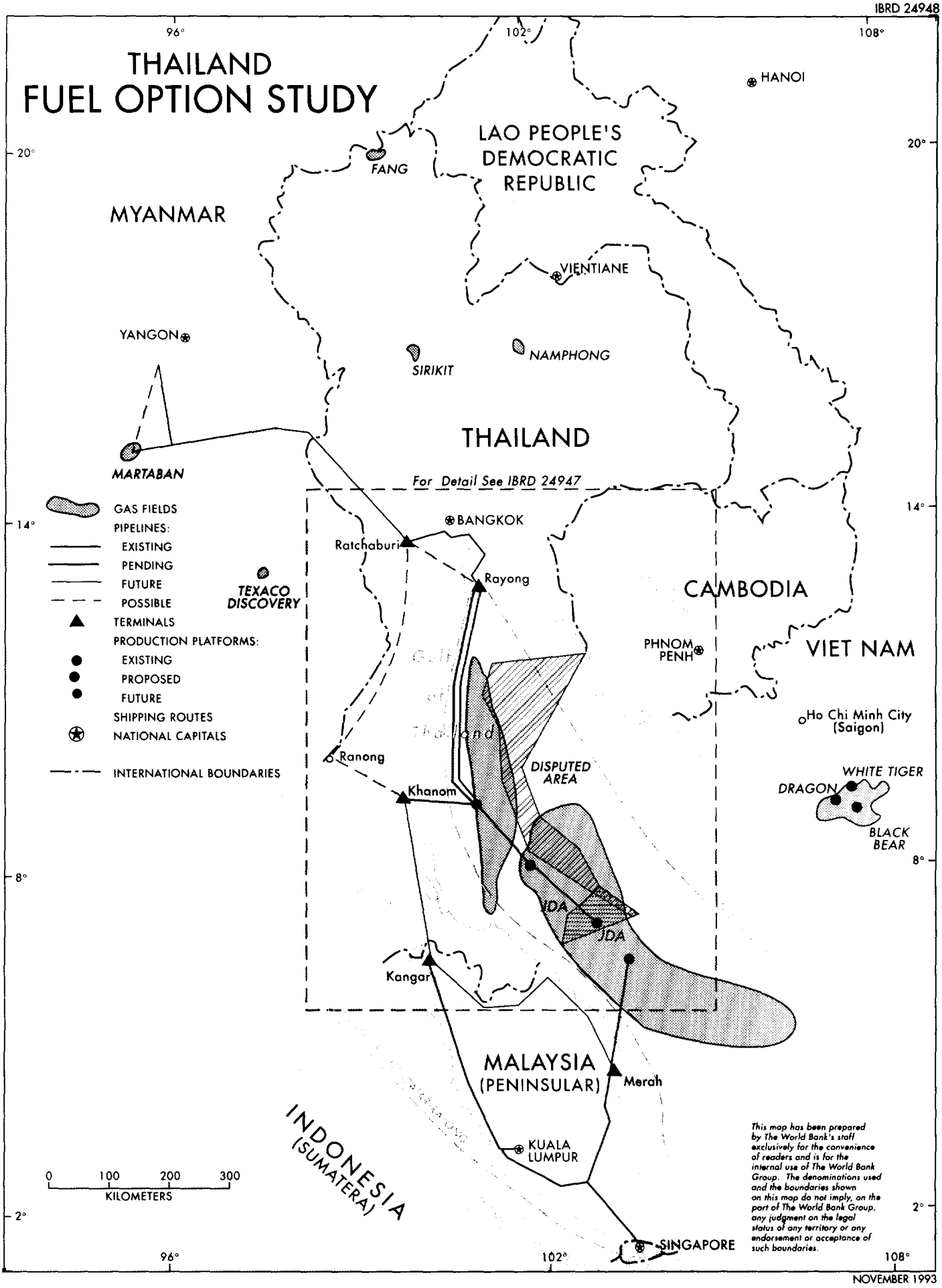
THAILAND
FUEL OPTION STUDY
96°
102°
108°
20°
14°
8°
2°
HANOI
LAO PEOPLE'S
DEMOCRATIC
REPUBLIC
FANG
MYANMAR
VIENTIANE
YANGON
SIRIKIT
NAMPHONG
THAILAND
MARTABAN
For Detail See IBRD 24947
GAS FIELDS
PIPELINES:
EXISTING
PENDING
FUTURE
POSSIBLE
TERMINALS
PRODUCTION PLATFORMS:
EXISTING
PROPOSED
FUTURE
SHIPPING ROUTES
NATIONAL CAPITALS
INTERNATIONAL BOUNDARIES
BANGKOK
Ratchaburi
Rayong
TEXACO
DISCOVERY
CAMBODIA
PHNOM
PENH
VIET NAM
Ho Chi Minh City
(Saigon)
Ranong
DISPUTED
AREA
WHITE TIGER
DRAGON
BLACK
BEAR
Khanom
JDA
JDA
Kangar
MALAYSIA
(PENINSULAR)
Merah
INDONESIA
(SUMATERA)
KUALA
LUMPUR
SINGAPORE
0
100
200
300
KILOMETERS
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