PD-WBA-243

Report with Recommendations on

COST STRUCTURE AND TRANSFER PRICING FOR THE PHILIPPINE PETROLEUM INDUSTRY

July 9, 1993

Prepared for:

DEPARTMENT OF ENERGY
Republic of the Philippines

Prepared by:

K&M ENGINEERING AND CONSULTING CORPORATION
2001 L Street, NW, Suite 500
Washington, DC 20036

The completion of this report was funded by the United States Agency for International Development (USAID) under a K&M Engineering and Consulting Corporation contract with the Office of Energy and Infrastructure, Bureau for Research and Development Contract No. DHI: 5738-Q-00-1089-00. The views, statements, and opinions contained in this report are the author's alone and are not intended as USAID recommendations, conclusions or statements of USAID policy.

3

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

- 1.1 Purpose of the Study
- 1.2 Recommendations
- 1.3 Background
- 1.4 World Oil Markets
- 1.5 Oil Products Production and Pricing
- 1.6 Refining Facilities and Efficiency
- 1.7 The Diesel Dilemma
- 1.8 Refining and Marketing: Returns, Profitability and Margins
- 1.9 Distribution and Dealer Margins; Futures Use in Setting Prices
- 1.10 Oil Price Stabilization
- 1.11 Economic Impact of Different Petroleum Pricing Regulations
- 1.12 Petroleum Product Prices, Taxes and Regulatory Practices in Other Countries
- 1.13 Control vs Decontrol of Oil Product Pricing
- 1.14 Privatization, Regulation, Energy Policy, Commodity Taxation, and Price Control
- 1.15 Implementation of Oil Price Decontrol

2. BACKGROUND, OBJECTIVES, AND METHODOLOGY

- 2.1 Purpose of the Report
- 2.2 Regulatory History and Establishment of Policy
- 2.3 Responsibilities of the ERB
- 2.4 Price Adjustments
- 2.5 Refining and Marketing Industry
- 2.6 Methodology
  - 2.6.1 Field Trips
  - 2.6.2 Modeling

3.0 WORLD OIL MARKETS

- 3.1 Crude Price Trends
- 3.2 Trends in Refined Products Markets
- 3.3 Crude and Product Price Differentials
- 3.4 Regional Variations in Product Markets
- 3.5 Refining Facilities in Regional Oil Markets
- 3.6 Summary and Recommendations

4.0 OIL PRODUCT PRODUCTION COST AND PRICING

- 4.1 Analysis of Diesel and Gasoline Incremental Production Cost
- 4.2 Refining Production Cost and Market Prices - Responsive Interaction
- 4.3 Oil Product Price Controls - Impacts on Market Interactions
- 4.4 Summary and Recommendations

5.0 REFINING FACILITIES AND EFFICIENCY

- 5.1 LP Model Solution Analysis
- 5.2 Oil Product Pricing and Refinery Facility Investment Decisions
  - 5.2.1 Future Refinery Facility Investments
- 5.3 Refinery Replacement Costs
- 5.4 Summary and Recommendations

TABLE OF CONTENTS
(Continued)

6.0 THE DIESEL DILEMMA
- 6.1 Diesel Pricing and the Supply/Demand Imbalance
- 6.2 Summary and Recommendations

7.0 TAXES ON PETROLEUM
- 7.1 Purpose of Taxes and Duties on Petroleum and Petroleum Products
  - 7.1.1 Generate Government Revenue
  - 7.1.2 Effect Social Goals
  - 7.1.3 Decrease Demand
  - 7.1.4 Shift Demand
  - 7.1.5 Protect Industries
  - 7.1.6 Improve the Environment
- 7.2 Philippine Taxes and Duties on Petroleum and Petroleum Products
  - 7.2.1 Current Duty and Tax Structure
  - 7.2.2 Aspects of the OPSF
  - 7.2.3 Analysis of Product Price Buildup March - 1992
  - 7.2.4 Characteristics of the Revenue Produced by Taxation
  - 7.2.5 Revenue Generation Options
- 7.3 Possibilities for Restructuring of Duties and Taxes
- 7.4 Summary and Recommendations

8.0 REFINING AND MARKETING: RETURNS, PROFITABILITY, AND MARGINS
- 8.1 Development of the Petroleum Industry
- 8.2 Oil Companies Returns on Sales, Assets, and Equity
  - 8.2.1 Returns of Philippine Oil Companies
  - 8.2.2 Returns of Oil Companies in Other Countries
  - 8.2.3 Comparison of Returns of the Philippine Companies with Other Countries
- 8.3 Refining and Marketing - Profitability and Margins
  - 8.3.1 Profitability and Margins - Philippine Companies
  - 8.3.2 Profitability and Margins - Other Countries
  - 8.3.3 Comparison of Philippine Companies' Returns with Others
- 8.4 Summary and Recommendations

9.0 DISTRIBUTION AND DEALER MARGINS - FUTURES USE IN SETTING PRICES
- 9.1 Product Distribution
- 9.2 Distribution and Transportation Pricing
- 9.3 Evaluation of ERB Authorized Distribution Rates
- 9.4 Dealer Margins
- 9.5 Use of Futures Markets to Stabilize Prices
  - 9.5.1 The Commodity Markets Mechanisms
  - 9.5.2 The New York Mercantile Exchange (NYMEX)
- 9.6 Use of Futures to Establish Product Prices in the Philippines
- 9.7 Use of Futures - Proforma 1987-1992
- 9.8 Recommendations on the Question of Using Futures for Price Stabilization
- 9.9 Summary and Recommendations

TABLE OF CONTENTS
(Continued)

10.0 OIL PRICE STABILIZATION
- 10.1 Oil Market Volatility
- 10.2 Oil Price Stabilization in the Philippines - Review of OPSF
- 10.3 OPSF - Possible Automatic Price Adjustment Mechanisms
- 10.4 OPSF and Energy Policy Social Goals
- 10.5 Oil Price Stabilization - The Pros and Cons
- 10.6 Oil Price Stabilization - Other Options
- 10.7 Summary and Recommendations

11.0 ECONOMIC IMPACT OF DIFFERENT PETROLEUM PRICING REGULATIONS
- 11.1 Description of the Model
  - 11.1.1 Prices
  - 11.1.2 Petroleum Demand
  - 11.1.3 Real Sector
- 11.2 Economic Impact of the Petroleum Product Price Deregulation
- 11.3 Summary and Recommendations

12.0 Summary and Recommendations
- 12.1 PETROLEUM PRODUCT PRICES, TAXES, AND REGULATORY PRACTICES IN OTHER COUNTRIES
  - 12.1.1 User Prices
  - 12.1.2 Taxes and Special Levies
- 12.2 Regulation of Petroleum Product Prices in Other Countries
- 12.3 Highlights of Price Regulation in Selected Countries
  - 12.3.1 Bolivia
  - 12.3.2 Chile
  - 12.3.3 South Korea
  - 12.3.4 Thailand
  - 12.3.5 Venezuela
- 12.4 Summary and Recommendations

13.0 CONTROL VERSUS DECONTROL OF OIL PRODUCT PRICING
- 13.1 Economic and Social Equity
- 13.2 Product Supply and Production Efficiency
  - 13.2.1 With Price Decontrol
  - 13.2.2 With Price Control
- 13.3 Meeting Future Processing Facility Needs
- 13.4 Oil Company Competition and Margins
  - 13.4.1 Possibilities of Competition Within the Controlled Environment
  - 13.4.2 Control of Margins
  - 13.4.3 Competition
- 13.5 Oil Price Stabilization
- 13.6 Revenue Generation, Taxes, and Consumer Prices
- 13.7 Options For Control and Decontrol
  - 13.7.1 Continuation of the existing OPSF and Controlled Pricing Approach. (Option 1)
  - 13.7.2 Continuation of the OPSF and Adoption of a New "Automatic Price Change Mechanism". (Option 2)

TABLE OF CONTENTS
(Continued)

13.7.3 Continuation of the OPSF, Adoption of the "Automatic Price Change Mechanism", and Restructuring of Taxes and Duties. (Option 3)
13.7.4 Elimination of the OPSF and Decontrol of Oil Product Pricing. (Option 4)
13.7.5 Elimination of the OPSF and Price Controls, Restructuring of Taxes and Duties Including a Legal System that Would Penalize Any Attempt to Reduce or Eliminate Competition. (Option 5)
13.7.6 Elimination of the OPSF and Price Controls, Restructuring of Taxes and Duties Without Control of Unfair Practices that Might Reduce Competition. (Option 6)
13.8 Comparison of Options
13.9 The "Price Control" vs "Price Decontrol" Decision
13.10 Implementation of Price Decontrol
13.11 Summary and Recommendations

14.0 PRIVATIZATION, REGULATION, ENERGY POLICY, COMMODITY TAXATION, AND PRICE CONTROLS
14.1 Privatization
14.1.1 Composition of the Private Sector
14.1.2 Reasons and Goals for the Segments Which Form Part of the Asset or Operation to Privatize
14.1.3 Justifications for Privatization
14.2 The Regulatory Process
14.2.1 What is Regulation?
14.2.2 A Brief History of "Sector" Regulation of Public Utilities
14.2.3 Regulatory Practices for the Private Sector
14.3 Energy Policy and Taxation
14.4 Privatization of Petron
14.4.1 Scenario 1 - Sale of Petron's Facilities to a Private Enterprise
14.4.2 Scenario 2 - Petron is Converted into a Share Company and its Shares are Sold in Stock Exchanges
14.4.3 Scenario 3 - Joint Ownership
14.4.4 Scenario 4 - Leasing of the Refinery
14.4.5 Scenario 5 - Petron is NOT Privatized
14.5 Steps to Implement the Above Scenarios
14.5.1 Scenario 1 - Sale to a Private Enterprise
14.5.2 Scenario 2 - Petron is Converted into a Share Company
14.5.3 Scenario 3 - Joint Ownership
14.5.4 Scenario 4 - Leasing of the Refinery
14.5.5 Scenario 5 - Petron is NOT Privatized
14.5.6 Time and Costs for the Privatization Process
14.6 Summary and Recommendations

15.0 IMPLEMENTATION OF THE OIL PRICE DECONTROL
15.1 Decontrol Issues
15.2 Transition Pricing - Recommended Pricing Strategy
15.3 Decontrol Steps and Timing
15.4 Summary and Recommendations

1 EXECUTIVE SUMMARY

1.1 Purpose of the Study

The U.S. Agency for International Development (AID) Mission in Manila (USAID/Manila) and the Office of Energy and Infrastructure commissioned K & M Engineering and Consulting Corporation (K&M) to carry out a study to review the Cost Structure and Transfer Pricing for the Philippine Petroleum Industry, under the Private Sector Energy Development (PSED) Program. The main objectives of this report are: to determine the appropriate oil policy guidelines, evaluate the current costs and regulatory conditions, analyze the capabilities of the oil refinery industry, and identify the present alternative approaches to the current Philippine oil industry pricing mechanisms.

Table 2-1, in Chapter 2, describes the tasks to be performed under this study. Specifically the study efforts include:

- Review of the operation of each of the three existing refineries and comparison of their efficiencies with accepted industry standards;
- Comparison of Philippine refining capabilities to anticipated product demand;
- Examination and evaluation of the actual practice and experience under Philippine regulations and policies, including development and consideration of alternative approaches;
- Recommendations concerning the appropriateness of current regulatory practice, including recommendations for changes and the steps needed and the timing desired;
- Documentation of other countries' experience and practice in petroleum regulation, including comparison of petroleum products cost to consumers in the Philippines with those of other countries;
- Documentation and analysis of world petroleum markets and their relationships, and the impacts on the Philippine cost and supply;
- Examination and forecast of world and regional demand of specific products, and corresponding impacts and relationships to the Philippines.

The staffs of the former Office of Energy Affairs (OEA) (now Department of Energy (DOE)), the Energy Regulatory Board (ERB), the three refineries and several teams of experts have worked in providing, assembling, and interpreting data pertaining to the study.

1.2 Recommendations

Actions should begin immediately toward implementation of regulatory reform and price decontrol. While K&M recommends that this should be accomplished within 18 months, specific actions required to meet the four-year time-frame limit for regulatory reform, called for in Republic Act 7638 of 1992, are discussed in Chapter 15. Other recommendations and specific steps required to implement the recommendations are also discussed in Chapter 15.

Specific actions recommended include the following:

1. A definitive action plan outlining the specific steps and dates to implement regulatory reform should be developed and formally approved.

2. Deregulate setting up of retail stations, depots and refineries.

3. Restructure duties and taxes on petroleum with new specific taxes on individual products while maintaining an essentially constant government revenue.

4. Specific minimum and maximum levels should be established for the OPSF during the transition. A model, developed by K&M to automatically make price changes to accomplish this, is discussed in Chapter 10.

5. The OPSF balance should be set above the minimum at the time of decontrol, and the disposition of the end balance of the OPSF should be decided prior to price decontrol.

6. The controlled price of distillates should be increased relative to gasoline prices during the transition period to provide incentives for its manufacturing and importing, and disincentives for its consumption.

7. Price changes by ERB should become more frequent during the transition period to accustom the public to the anticipated frequent changes following decontrol.

8. Define the actions needed to assure a competitive oil products market after decontrol.

9. Procedures currently used by ERB for setting distribution allowance should continue until price decontrol becomes effective.

10. A study should be made of dealer costs, investment and returns to provide ERB adequate basis for setting dealer margins during the transition period.

11. Foreign exchange cover should be phased out and its economic impact should be reflected in the DOCT (Direct Oil Company Take).

12. DOCT should be adjusted to reflect increased oil company expenses. Consideration should be given to further increases to provide higher margins required for increased returns to the companies.

13. Actions required to privatize Petron should begin as soon as possible with completion targeted for the same time as price decontrol. Options for privatization are discussed in Chapter 14.

1.3 Background

Regulatory activities for the Philippine oil industry started in 1973 with the creation of the Philippine National Oil Company (PNOC). Since then there have been several policy and price setting institutions, to which different duties were assigned. In December 1992 a new Republic Act (RA 7638) redefined the regulatory and price duties that are now the responsibility of the Department of Energy (DOE) and the Energy Regulatory Board (ERB).

The refining and marketing industry in the Philippines consists of three companies: Petron, Caltex, and Shell. Petron is a wholly owned subsidiary of PNOC while the other two companies are subsidiaries of Chevron and Texaco (Caltex), and Shell (Shell).

While the total refinery capacity exceeds the total product demand, the refineries are not capable of producing all the products required by the Philippine economy. Existing pricing policies favored some products (such as diesel) without giving sufficient consideration to production costs, which resulted in shortages in the supply of these products.

The Oil Price Stabilization Fund (OPSF) was established in 1984 with the aim of dampening fluctuations of domestic oil product prices when the world prices of crude oil swing. Since social considerations distorted the implementation of the principles guiding the OPSF, there were times when it accumulated a large deficit, which had to be eliminated by subsequent large price adjustments.

At the request of USAID Manila, a presentation was made by the K&M team in September 1992 based on very preliminary investigations and tentative conclusions which recommended elimination of product price control as soon as practical with no time frame specified. In its presentation in March 1993, the K&M team recommended regulation reform and price decontrol during a 15/18 month time frame. However, the Republic Act 7638 of 1992 states: "At the end of four years from the effectivity of this Act, the Department shall, upon approval of the President, institute the programs and timetable of deregulation of appropriate energy projects and activities of the energy industry".

A report, entitled "Technical Report", was submitted for comments in November 1992 and the final version is dated February 1993. It describes the technical characteristics of the Philippine refineries and how they are affected by the world crude oil supply. The Executive Summary of the Technical Report is reproduced in Appendix 3.

1.4 World Oil Markets

World crude oil prices have gone through several transitions over the past twenty years. In the 70's the Organization of Petroleum Exporting Countries (OPEC) became a cohesive force that controlled a very large part of crude production during a period of tight supply. Price spikes resulted from political events and new dramatically higher levels of prices were established.

The much higher price of petroleum brought about energy conservation, fuel switching, and increased exploration throughout the world. This resulted in surplus supply and a significant drop in prices in 1986. Political events since then have caused price spikes but all were short lived due to excess production capacity. Most forecasters anticipate moderately higher prices in the future. It is anticipated that these price increases will follow a pattern of spikes (resulting from political or other unpredicted events) and declines but to a higher plateau than was evident before each spike.

The most significant change over this period has been the decline in the demand for heavy fuels with 1991 volumes being only about half of that of 1975. Fuel substitution and increased conversion of the heavy portion of crude to lighter products have caused the fuel oil production to represent a lower part of the refined product slate.

The relative reduced demand for fuel oil has resulted in increased price differentials and ratios between light and heavy products and between light and heavy crude.

Other major changes over the past twenty years in the refined product markets have been the more stringent quality requirements to meet environmental improvement efforts. Lead has been completely removed in most gasolines and greatly reduced in areas where it is still permitted. Additional octane upgrading hardware is required to offset the octane boost formerly provided by Tetra-ethyl lead (TEL). In addition, reformulation of gasoline, reduced sulfur specifications for distillates and fuel oil, restriction on aromatic content of gasoline and diesel, as well as more restrictive regulations governing refinery operations have required massive investments and increased cost of refining crude into acceptable products.

World oil markets are more transparent than those of twenty years ago. Real crude and product prices tend to equalize throughout the world once adjusted for freight and other added costs. Disequilibrium in prices are short lived as sellers seek the higher markets and buyers seek the lower cost supply.

1.5 Oil Products Production and Pricing

A Linear Program (LP) model was developed and documented for each of the three Philippine refineries. Training sessions and manuals were furnished to DOE for its use in further analysis of policy issues involving the Philippine refining industry.

The cost of production of a refined product changes as the production level of that product changes. The cost at any level of production depends on a number of variables including crude selection, availability, cost, assay, product specifications, yield correlations, variable cost of refinery units, unit capacities, variability of operations, and production levels of other products being co-produced.

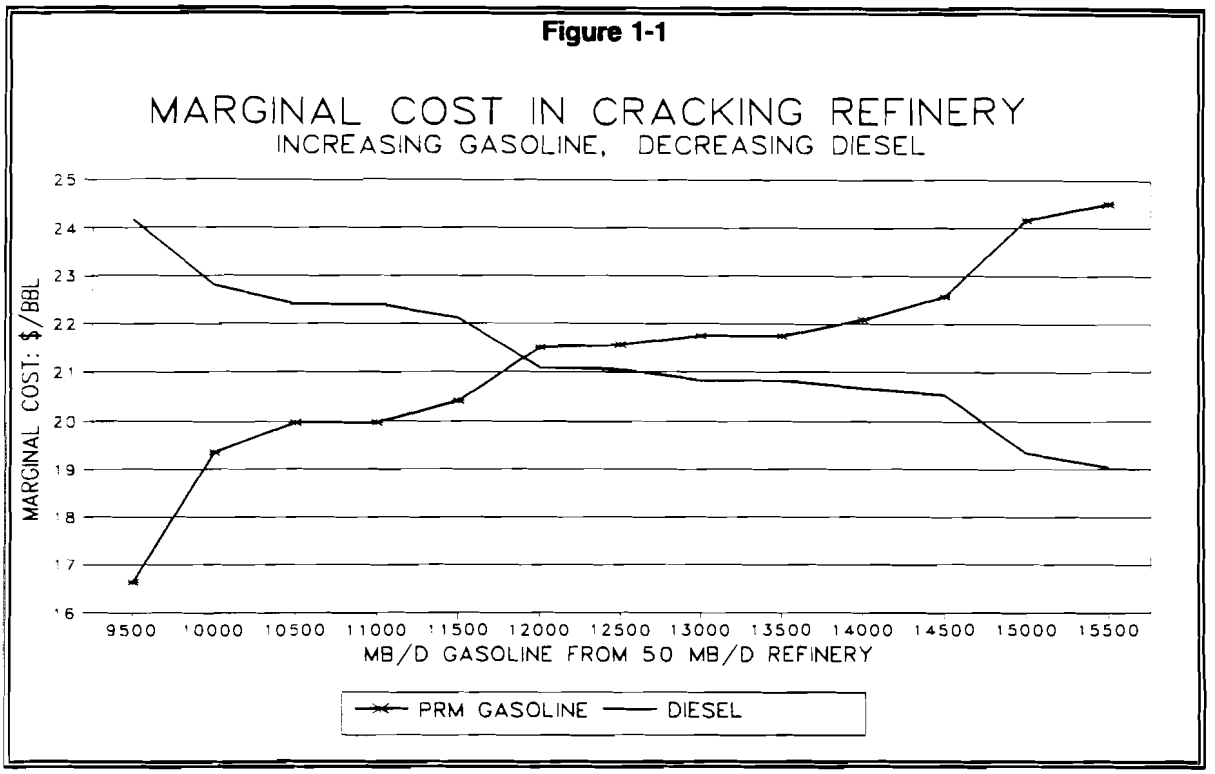
Analyses demonstrate that the marginal cost of producing a given product at a low level of production is much less costly than when production of that product is pushed to near maximum levels. As an example, the marginal cost of diesel production in a 50,000 bbl/d FCC refinery was shown to be about $19 per barrel at a production level of 10,500 bbl/d but increased to over $24 per barrel when production was forced to 16,500 bbl/d. Similarly, the marginal cost of premium gasoline was about $17 when total gasoline production was set at 9,500 bbl/d but increased to over $24 at a gasoline production level of 15,500 bbl/d. This second scenario is shown graphically in Figure 1-1.

Diesel prices in the Philippines have been set low relative to gasoline resulting in a distortion of diesel demand. The Philippine refiners are at maximum economic diesel production levels. The low price at which diesel has been set in the control pricing scheme has been a major factor in the reasons that diesel has increased from 18.5% of product demand in 1975 to an estimate 33.7% in 1992.

1.6 Refining Facilities and Efficiency

Several cases were developed using refinery Linear Programming models (LP) described in Chapter 4. The results of these cases quantify the impact of price on the optimum crude selection and optimum product slate for each of the refineries investigated. Cases were also analyzed that forced production of specific products at a non-optimal level to determine the effect on crude selection and economics.

Figure 1-1



Comparisons of optimum operations, as depicted by the LP solutions, with that of actual operations were made. Not surprisingly, the optimum solutions indicates more gasoline and less distillate should be produced than actually the case. This is due to refiners' tendency to maximize diesel while limiting gasoline production to meet local demand. In other words, refiners strived to meet demand although the controlled price structure indicated more gasoline and less diesel would be more economical assuming the additional gasoline could be sold in the local market. The refiners were attempting to meet the needs of the market with the economic penalty of generating lower margins.

Government controlled prices play an enormous role in supply/demand patterns and, accordingly, the economics of refinery investments. Demand is influenced by price and it is irrelevant to the consumer whether that price results from DOCT, taxes, OPSF, dealer margins or other factors. Economics of supply is partially dictated by netback to the supplier. The controlled low prices for diesel distorted demand upward while distorting the economics of supply downward.

Refiners cannot make rational decisions on investments without knowledge of future energy policies, i.e., pricing by the government. No LP runs were made to define future hardware requirements due to the uncertainty of demand and pricing, and government policy. Economics of conversion hardware to increase diesel production were reviewed and it was concluded that regulated prices did not provide adequate incentives for large increase in diesel production capabilities.

Rough estimates were made of the replacement cost of the three Philippine refineries as they are planned to exist in 1994: Caltex, $780 MM; Petron, $1,021 MM; and Shell, $949 MM. It is doubtful that many, if any, refineries would be replaced with their present

configurations. Changes would be made to reflect technical advances, changes in crude supply, product demand, etc. Thus, replacement cost does not necessarily correlate with actual value of an existing refinery.

1.7 The Diesel Dilemma

The Philippines has had a social policy in which diesel fuel oil was priced lower than gasoline to provide a lower priced fuel for jeepneys and buses, thereby reducing the costs of public transportation for the poorer segments of the population. This policy has caused diesel demand to grow much more rapidly than gasoline. The diesel demand growth rates have accelerated in recent years. As diesel demand has become a higher fraction of the oil product barrel it has become more difficult for refiners to meet the demand requirement. Attracting diesel imports has also become difficult because the controlled price and the import duties make imports uneconomical.

A number of recommendations have been made to help remedy the "diesel dilemma":

1. Remove the import duty on diesel and replace with a specific tax
2. Increase the refinery gate price relative to gasoline (higher than Singapore Import Parity), but reduce the consumer gasoline-diesel differential
3. Deregulate product importation
4. Increase duties on new diesel engines and diesel vehicles with lower duties or compensating benefits for public transportation vehicles

The objective of these recommendations is to provide increased diesel supply in the short term and diminish diesel growth rates in the longer term.

Taxes on Oil Product

Taxes are imposed on petroleum with one or more of the following objectives:

1. Generate government revenues
2. Effect social goals
3. Decrease demand
4. Shift demand
5. Protect industries
6. Improve the environment

Petroleum is taxed in the Philippines in three ways; (1) import duties of 19% on crude and 29% on products, (2) special duty of 1.00 peso per liter on all products, and (3) specific taxes on selected products. In addition, product prices are adjusted both up and down by application of the OPSF, although the OPSF is not a tax.

Taxes and duties equate to about one third of the consumer price for products, on average. About one half of the consumer costs reflects the feedstock costs and the balance covers the refining, marketing, hauling, and dealer costs and profits.

The current tax and duty structure appear to be mostly non-selective as 74% of the taxes/duties are applied equally to all products and only 26% are specific taxes on selected products. It has been illustrated how the government revenue from petroleum taxes/duties can be held constant while redistributing the taxes and duties selectively over the various petroleum products.

It is recommended that the taxes and duties on petroleum be restructured in a manner to target specific products for various levels of taxes, which more clearly reflects the government's multiple goals in petroleum taxation. Specific recommendations are presented in Chapter 15, Implementation of Oil Price Decontrol.

1.8 Refining and Marketing: Returns, Profitability and Margins

Refining and Marketing divisions (R & M) of integrated oil companies generally produce lower profitability and returns than the Exploration and Production divisions (E & P) and other segments of the industry. Direct, explicit comparisons of the financial performance of the Philippine refining and marketing companies with that of similar companies in other countries are not possible due to the unavailability of specific data on R & M companies or divisions required for such a comparison. However, several benchmarks were developed so that general comparisons are possible and an overall assessment can be made.

Comparisons of return on sales, assets and equity for the Philippine companies with that of six integrated international companies and eight US domestic companies are presented below:

Table 1-1

	Rates of Return, 1987 - 1991		
Companies	Sales	Assets	Equity
Caltex	2.0	3.5	21.1
Petron	3.2	4.6	23.0
Shell	3.4	4.6	14.5
Philippine Industry	2.9	4.3	18.7
Six Internationals	4.6	5.4	11.8
Eight US Independents	5.0	4.8	15.5

Returns on sales are distorted in all cases since sales revenue includes taxes which are passed on to the governments. However, the revenue for the six internationals and the eight US domestics include a large portion of sales as crude oil, chemicals, and other sales which generally have a higher markup over cost and lower tax burden than refined products. Therefore, it should be expected that the percent return on sales would be lower for refining and marketing companies.

Returns on assets are greater for the six internationals and the eight US domestics than that realized by the Philippine companies. Again, E & P, chemicals, and other segments of the industry have historically generated more attractive returns than have the R & M sectors. However, a rate of return of 4.3%, as experienced by the Philippine companies over the five year period, is inadequate to generate the required cash flow to sustain an efficiently viable operation and is even less adequate to allow for future expansions.

Returns on equity were greater for the Philippine companies than that for either of the other two groups. Returns on equity are highly influenced by debt policy or requirements. Leverage increases return but is accompanied with increased risk.

ERB was granted a price increase of 0.12 peso/liter in October 1992. This amount of increased revenue (after 35% income tax) will increase the return on sales by 1.1%, return on assets by 2.0% and return on equity by 8.5%. Had this increase been in effect for all of 1991, the return on assets would have been 8.4% for the Philippine R&M industry.

Extensive data were presented depicting margins of Philippine, US Gulf/West Coast, Singapore, and Rotterdam refineries. Additional data was presented on US Gulf Coast refinery profitability over an eleven year period. While the data is not directly comparable due to the different types of markets, varying complexities of the refineries, etc, some insights were observed. Refining margins are highly volatile throughout the world. Considering the relatively low complexity of the Philippine refineries and the differences in the markets, the margin realized is not greatly out of line with that of refineries in other locations. Table 1-2 depicts adjusted as well as raw margins for the Philippines as compared to those of Singapore, US Gulf/West Coast, and Rotterdam.

Table 1-2

Margin Comparison
1990-91

	US$/Barrel	
	Base	Adjusted
Philippine Refineries	2.15	2.15
Singapore Refinery	2.48	3.85
Rotterdam Refinery	1.78	3.15
US Gulf/West Coast Refinery	3.34	4.71

In summary, refining and marketing investments have generated, at best, only marginally attractive returns. The experience of the Philippine companies have been in line, but slightly lower than that of the other countries' refineries for which data were available. The returns realized by the Philippine have not been adequate to fully justify additional investments. With the 0.12 peso/liter price increase granted in October should increase return on equity to 8-9%. Another increase of similar size should increase returns to 10-11% which would make additional investments more acceptable to shareholders.

1.9 Distribution and Dealer Margins; Futures Use in Setting Prices

A review of the procedures used by ERB in setting transportation allowance based on marine and pipeline costs indicated the process to be adequate. A detailed review of the adjustments granted by ERB in April 1992 for transportation allowances for both white and black oils were generally appropriate while some adjustments may be desirable between white and black products.

Procedures for setting dealer margins appear to be weak. The data available to ERB is lacking but it appears that the allowances granted are reasonably appropriate based on dealer applications and withdrawals from the market. It is recommended that a detailed study be made of dealer costs, investments, and returns analysis be made so that ERB would have a better documented basis for setting appropriate margins.

Use of futures in setting controlled product prices was reviewed in some detail. Although such a procedure could result in more accurate forecasting of future consumer prices, it is doubtful that either the public or the government would be willing to accept a situation where current prices, set in accordance with futures mechanisms, were higher than those based on the then-current world market prices. It is recommended that futures not be used in establishing controlled prices.

1.10 Oil Price Stabilization

The Oil Price Stabilization Fund (OPSF) was established to help stabilize petroleum product prices and minimize the frequency of price changes to the consumer. When the average cif price of crude is lower than the established crude price used in setting product prices the oil companies pay the difference into the OPSF. Conversely, when the crude c.i.f. price is higher, the oil companies withdraw the difference.

The frequency of price changes have been reduced through the OPSF price setting mechanism. The average price paid by the consumer has not been reduced since, ultimately, the full crude costs must be recovered in the marketplace.

Since the OPSF was instituted in 1984 it has experienced some major problems. Adequate changes in product prices have not always been timely. The Fund was allowed to incur deficits approaching 17 billion pesos (US$ 680 million) in November 1990 before prices were increased to offset the higher crude costs resulting from the Gulf War and other increases prior to the war.

If the OPSF is to be continued, an automatic price change mechanism should be implemented which would decrease the political pressures to maintain lower prices when crude price increases occur and should maintain the OPSF balance in a more acceptable range. A detailed model has been developed and described. A pro forma example of how it would work is discussed.

The OPSF has also been used to help achieve social goals through cross subsidization of "social" products through higher prices for "luxury" products. Examples were shown which illustrate how prices could be maintained through specific taxes rather than use of the OPSF mechanism. At the same time government revenues were held essentially constant.

Use of strategic petroleum reserves (SPR) to stabilize prices would not be prudent. The cost of establishing and maintaining an SPR is enormous. The Philippines should benefit from the SPRs of more economically advantaged countries who attempt to moderate crude price increases through drawdown, or mere threat of drawdown, of very large reserves.

1.11 Economic Impact of Different Petroleum Pricing Regulations

A monthly econometric model was developed to quantify the impact of product prices of various pricing scenarios. This model was linked to a petroleum demand model reflecting change in demand of fuel oil, diesel, gasoline, and LPG with price.

Six scenarios were defined and the results on certain aspects of the Philippines were investigated.

The case where the OPSF was eliminated and prices were continued at the current level (excluding the impact of OPSF subsidy/add-on) would be the most disruptive to the economy with a 2.9% reduction in GNP, a decrease of 5.8% in per capita income, an increase of 0.3% in CPI, decrease the nominal loan rate by 0.48%, all relative to Case B, current sustainable case. This is to be expected since both diesel and fuel oil would lose subsidization through the elimination of the OPSF and both products are important inputs to the industrial sector.

Increasing gasoline and avtur (Aviation Fuel) with offsetting increase in kerosene and diesel would have little impact.

Decreased fuel oil prices with offsetting increases in kerosene and diesel would increase the GNP by 1.7%, and have essentially no effect on the average per capita income, CPI, or nominal loan rate.

1.12 Petroleum Product Prices, Taxes, and Regulatory Practices in Other Countries

Comparisons were made of consumer prices in the Philippines and those of 60 other countries for which prices were available. The data shows that consumer prices for gasoline and diesel are higher in about three-fourths of the countries in the survey than they are in the Philippines. Prices for kerosene, LPG, and fuel oil are higher in a little over half of the other countries. Prices for jet fuel in the Philippines were among the lowest for which there were data.

Taxes contribute to a large part of the consumer prices in most countries. Comparison of taxes in the Philippines present a pattern similar to that of total consumer prices. Taxes on gasoline and diesel were higher in more than three-fourths of the other countries. Kerosene, LPG, and fuel oil had higher tax rates in 30-40% of the countries than that of the Philippines. See Table 1-3 for specific comparisons.

Overall, based on the survey data, petroleum product prices in the Philippines are more favorable to the consumer than they are in most countries of the world. This is largely due to the lower tax burden in the Philippines.

There is a definite trend to decrease the amount of control of product prices throughout the world. Countries with price controls on all petroleum products decreased from 63% in 1984 to 22% in 1991 while those with no price controls increased from 24% to 30%. Those with price controls on some, but not all, products increased from 13% to 48%.

Table 1-3
Percent of Countries With Taxes and Levies Higher than in the Philippines

	Percentage
LPG	41
Regular Gasoline	78
Premium Gasoline	83
Diesel	76
Jet Fuel	10
Kerosene	36
Heavy Fuel	31

A review of regulatory history in Bolivia, Chile, South Korea, Thailand and Venezuela indicate that regulations are being relaxed and price movements toward world market prices are being effected. Several of the countries had funds somewhat similar, but not utilized in exactly the same manner, to the Philippines Oil Price Stabilization Fund.

1.13 Control vs Decontrol of Oil Product Pricing

Several factors affected by the control versus decontrol issues have been identified and discussed. These factors include:

1. Economic and social equity,
2. Product supply and production efficiency,
3. Future processing facilities needs,
4. Oil company competition and margins,
5. Oil price stabilization,
6. Government revenue generation and taxes, and
7. Consumer prices.

Economic and social equity can be addressed equally well under control or decontrol. Supply problems have been compounded under controls and would be better resolved under a decontrolled environment. Oil companies would be in a better position to resolve investment issues in the absence of unpredictable regulatory mandates. Competition among the oil companies is a legitimate concern with only three players but should be acceptable with proper governmental monitoring. Margins would be more volatile under decontrol. Oil prices would probably change more frequently in a decontrolled market but the average prices would not necessarily be higher than that under an efficiently administered price control. Government revenue could be maintained through proper restructure of taxes and duties.

Six scenarios of control/decontrol were analyzed. These were:

1. Continuation of OPSF and controlled prices,
2. Continue OPSF but with automatic price changes,
3. Same as 2 but restructure taxes,
4. Eliminate OPSF and price controls,

5. Eliminate OPSF, decontrol prices, restructure taxes, and include a legal system to penalize attempts to reduce competition,
6. Same as 5 but no monitoring or structured penalties for non-competitive marketing.

Option 5. eliminate OPSF, decontrol prices, restructuring taxes, and include a legal system to assure competition is considered the best alternative. It should assure reasonable prices to the consumer, government social goals, and revenue objectives could be met through tax policies, refiners would be better able to project demand/prices for investment decisions and competition should be satisfactory. The other options would require additional governmental burdens and/or not provide a sufficiently competitive environment.

1.14 Privatization, Regulation, Energy Policy, Commodity Taxation and Price Control Implementation of Oil Price Decontrol

There are several ways the private sector can participate in the oil industry. Usually the main justifications for the privatization of components of the public sector are the desire to obtain increased efficiency and also to obtain hard currency to pay for the national debt.

Privatization should be accompanied by regulation, which is the process that must be set up to protect the interests of both the public and the participants from the private sector. Regulation is not price control: it is the establishment and enforcement of the rules under which all participants must operate. Effective regulation, by decreasing the risks of the investors, will also decrease the prices to the consumers.

The privatization of Petron may take many forms, the preferred one being the sale of assets to a private enterprise. This option would require several preliminary steps, including: (i) amendments to the existing legislation, (ii) preparation of the bid documentation that must cover technical, commercial, legal, and financial aspects, (iii) the development of evaluation criteria for the bids, (iv) the establishment of acceptable schedules to recognize the timing required to put together the financial aspects of the sale.

Various scenarios can be envisioned for the implementation of the regulatory reform required to ascertain a free market economy for the petroleum refining subsector; including legal, price control and stabilization issues. A detailed possible scenario and its components steps are included in Chapter 14 to describe some of the issues that might arise.

1.15 Implementation of Oil Price Decontrol

An effectively planned and run decontrol transition process that occurs before the actual elimination of oil product price controls can contribute greatly to the success of decontrol. The transition process will require action and the committed efforts of DOE and ERB along with the active support of other administrative and legislative bodies.

This report recommended that actions need to be taken in a number of areas to bring about the transition, including:

- Responding to the diesel supply/demand problem,
- Organizing and coordinating the Decontrol Transition Process,
- Planning for the end of the OPSF and disposition of the end balance,

- Taking needed steps to ensure a competitive oil product market place after decontrol, and
- Implementing "Phase-in" activities to adapt the public to increased frequency of price changes and converging control price into decontrol prices.

The specific steps to accomplish this are outlined in Table 1-4. The top items should be taken care of as soon as possible. K&M has recommended an 18-month period for the transition process to achieve the benefits of decontrol as quickly as possible. It would appear that a longer time period is favored in the Philippines, so the transition process has been designed to allow for flexibility in adjusting the time frame. It is, however, critically important that the process and effort begin without delay.

Table 1-4

DECONTROL STEPS AND TIMING

DECONTROL ACTIVITIES	ACTION ITEMS	TIMING
DIESEL DILEMMA	Restructuring of Taxes and Duties Deregulation of Product Imports Refinery Gate Pricing Revision Duties on Diesel Engines/Vehicles	As Soon As Possible(1/94) As Soon As Possible(10/93) As Soon As Possible(1/94) As Soon As Possible(1/94)
ORGANIZATIONAL	Designation of DOE Policy Analysis Responsibility Decontrol Coordination with ERB, Legislature, etc.	As Soon As Possible(10/93) As Soon As Possible(1/94)
OPSF	Min/Max Price Adjustment Process Implementation Setting of End Balance Target & Fund Disposition	When Bill Effective Policy Position in 6 Months(1/94)
INDUSTRY COMPETITION	Oil Products Marketing Deregulation Service Station Decontrol Petron Privitization Oil Data Submission Requirements Rules &Enforcement for Anti Competitive Practices	When Practical to Implement(1/95) At Least 12 M's Before Decontrol If Done, Before Decontrol Date At Least 9 M's Before Decontrol At Least 9 M's Before Decontrol
PHASE-IN TO DECONTROL	Margin Adjustment - Forex Cover & Regional Level Window for Decontrol Day Increased Price Adjustment Frequency Align Control Prices to Decontrol Prices	When Resolved as Policy Issue Next 3-9 Months At Least 18 M's Before Decontrol During Frequent Adjustment Period

2 BACKGROUND, OBJECTIVES, AND METHODOLOGY

This chapter describes the purposes of the work that was carried out, the methodologies used to perform the work and the regulatory/energy policy setting environment in the Philippines.

2.1 Purpose of the Report

The U.S. Agency for International Development (AID) Mission in Manila (USAID/Manila) and the AID Office of Energy and Infrastructure have commissioned K&M Engineering and Consulting Corporation (K&M) to carry out a study to establish the Cost Structure and Transfer Pricing for the Philippine Petroleum Industry, under the Private Sector Energy Development (PSED) Program. The main objectives of this report are: to determine oil policy guidelines, evaluate the current cost and regulatory conditions, analyze the capabilities of the oil refinery industry, and identify the present alternative approaches to the current Philippine oil industry pricing mechanisms. Table 2-1 describes the tasks to be performed under this study. Specifically the study efforts include:

- Review of the operation of each of the three existing refineries and comparison of efficiencies with accepted industry standards;
- Comparison of the Philippine refining capabilities to anticipated product demand;
- Examination and evaluation of the actual practice and experience under the Philippine regulations and policy, including development and consideration of alternative approaches;
- Offer recommendations concerning the appropriateness of current regulatory practice, including recommendations for changes and the steps needed and timing desired;
- Documentation of other countries' experience and practice in petroleum regulation, including comparisons of petroleum products costs to consumers in the Philippines with those of other countries;
- Document and analyze world petroleum markets and their relationships and impacts on the Philippine cost and supply; and
- Examine forecast world and regional demand forecast of specific products and corresponding impacts and relationships to the Philippines.

The staffs of the formerly Office of Energy Affairs (OEA) (now Department of Energy (DOE)), the Energy Regulatory Board (ERB), the three refineries, and several teams of experts have worked in providing, assembling, and interpreting data pertaining to the overall Petroleum subsector.

In the text of this report we will refer to the previous activities of OEA as if they were performed by DOE, even though they were carried out prior to Republic Act (RA) 7638 of 1992.

2.2 Regulatory History and Establishment of Policy

The Philippine petroleum industry has been heavily regulated since the early 1970's and since then it has been reorganized several times. The following are the main benchmarks in the establishment of the regulatory framework:

- The Philippine National Oil Company (PNOC) was created in 1973 by Presidential Decree (PD) 334 to provide an adequate and stable supply of crude oil.

- The Ministry of Energy (MOE) was established in 1977 by PD 1206 to formulate and implement government policies, plans and programs on energy resource development.

  Within the MOE, the Bureau of Energy Development (BED) and the Bureau of Energy Utilization (BEU) were created. The BED was to administer a national program for the encouragement, guidance and, where necessary, the regulation of business activities related to the exploration, exploitation, development and extraction of fossil fuels (petroleum, coal, natural gas and gas liquids), nuclear fuel resources, geothermal energy resources, and non-conventional energies. BEU functions were: to administer a national program for the encouragement, guidance and, where necessary, the regulation of business activities related to importing, exporting, shipping, transporting, refining, processing, marketing, and distributing energy resources.

  The same Decree also established the Board of Energy, which reported to the Office of the President.

  The Oil Industry Commission was created on April 30, 1977 by R.A. 6173 to regulate the oil industry by assuring the public an adequate supply of petroleum products at reasonable prices and assuring investors fair return on their investments.

- In 1986, Executive Order (EO) 20 placed the MOE under the Office of the President.

- EO 172, in 1987, reconstituted the Board of Energy into the Energy Regulatory Board (ERB). The ERB responsibilities include all of the regulatory and adjudicatory functions related to licensing of crude oil, refined petroleum products, importations/exportations and the regulation of petroleum refining and marketing. In addition, it was empowered to regulate coal imports and to set prices of petroleum products sold by oil companies and dealers. It was also given jurisdiction over tariff setting for electric utilities.

- In 1988, EO 193 provided for the creation of the Office of Energy Affairs (OEA), replacing the MOE. The OEA had the responsibility of formulating, planning, implementing, monitoring, and coordinating policies and programs in the energy field. The OEA was a unit in the President's office.

- E0 338, in 1988 created the Energy Coordinating Council (ECC) to provide the mechanism for the coordinated review and discussion of integrated energy resource management strategies, national energy plans, and the policies and programs of energy agencies. Originally the board was chaired by the Executive Secretary and had representatives from: (i) the PNOC, (ii) the National Power Corporation (NPC), (iii) the National Electrification Administration. A subsequent amendment of the ECC charter transferred the chairmanship to the Presidential Adviser on Energy Affairs.

- The RA 7638 of 1992 included provisions which:

  (a) Created the Department of Energy (DOE), whose responsibilities are to prepare, integrate, coordinate, supervise and control all plans, programs, projects and activities of the Government relative to energy exploration, development, utilization, distribution, and conservation.

  (b) Transferred to the DOE the non-price regulatory powers and functions formerly assigned to the ERB under EO 172. These include: refining capacities, licensing of retail outlets, transportation of products, and imports and exports of petroleum crude and oil products.

  (c) Abolished the ECC and transferred its functions and powers to the DOE.

2.3 Responsibilities of the ERB

The ERB has authority to regulate essentially all sectors of energy in the Philippines. This not only covers the petroleum industry but also the electric power generation and distribution, coal mining and geothermal industries.

The ERB authority in the refining and marketing sector of the petroleum industry permits it to set specific prices for all petroleum products at each level of distribution. It also has authority to regulate refining capacities, licensing of retail outlets, transportation of products, imports and exports of petroleum crude oil and products.

RA 7638 transferred to ERB the power, formerly assigned to NPC and to the electric cooperatives, to determine, fix, and prescribe the rates charged to their customers. ERB will exercise its new powers only after due notice and hearing, and follow the same procedures described in its original enabling legislation (EO 172).

2.4 Price Adjustments

PD 1956 created the Oil Price Stabilization Fund (OPSF) in 1984. The OPSF was established to help dampen the violent price fluctuations in petroleum products. Generally monies are paid into the OPSF by the oil companies during periods of rapid decreases of crude prices and resultant over-recovery of costs, and are paid out of the OPSF to the oil companies when rapid increases in crude prices result in under-recovery of costs. Through the use of the OPSF buffer, the consumer prices are not subject to changes as volatility as they would be in absent the OPSF.

The framework of the regulations appears adequate to allow adjustments in prices and in oil company take (the amount the oil companies receive for products), and to generate an acceptable return. The administration and results of these regulatory practices have not been met with universal approval. The Direct Oil Company Take (DOCT) has been adjusted bi-monthly to reflect changes in the peso cost of crude and adjustments in distribution costs. Until the price adjustments in November 1992, the last increase in DOCT for increased refining and marketing expenses was in 1986. The oil companies had petitioned for increase in the DOCT to cover increased operating expenses without success.

Adjustments in consumer prices have been relatively infrequent. Increases have been met with strong objections from the general public. As a result, price changes have become very politicized, creating an understandable reluctance to increase prices in a timely fashion. The OPSF was allowed to grow into a deficit of over 16 billion pesos as a fallout of the increase in crude prices during the Iraq/Kuwait crisis. Ultimately, consumer prices were adjusted but, when crude prices dropped the OPSF grew to a positive 8 billion pesos.

2.5 Refining And Marketing Industry

The refining and marketing industry principally consists of three companies: (i) Caltex (Philippines) Inc., a wholly owned subsidiary of Caltex Petroleum Corporation, a U.S.A. corporation; (ii) Petron Corporation, a wholly owned subsidiary of the Philippine National Oil Company; and (iii) Pilipinas Shell Petroleum Corporation, a wholly owned subsidiary of the Royal Dutch/Shell Transport Group.

The total refining capacity of the Philippines is approximately 300,000 bbl/d composed of Petron at 155,000 bbl/d, Shell at 73,000 bbl/d and Caltex at 71,000 bbl/d. While the total refining capacity exceeds the total petroleum product demand, the refineries are not capable of producing all the products required by the Philippine economy. Refinery throughput for 1991 was about 214,000 bbl/d, versus capacity of 300,000 bbl/d and demand of 227,000 bbl/d. The refineries are not as complex (a measure of the extent of conversion and upgrading capacity) as world scale refineries and therefore have relatively low conversion capability (converting the heavy part of the crude into lighter fractions).

The refineries are operated to maximize production of lighter products according to economic feasibility. The yields from such an operation result in shortfalls of diesel, heavy fuel oil and LPG, and some excess of gasoline feedstocks and blendstocks. The shortfalls are covered by imports and the excess products are exported. The social pricing of diesel aggravates the natural shortfall and makes its importation unattractive. As a result, the supply/demand balance is worsening.

The distribution and marketing of products from the three refineries covers the length and breadth of the Philippine archipelago. Transportation and logistic facilities include pipelines, 42 ocean going tankers, 27 barges, and 85 terminals and bulk plants. The marketing facilities include 3,261 gasoline stations, 527 LPG dealers, and numerous industrial and commercial consumers.

2.6 Methodology

The methodology for conducting this study consisted of field trips to the Philippines, discussions with experienced personnel, research of available literature, development and analysis of the output of linear programs (LP), creation and analysis of spreadsheet models,

and timely reviews of conclusions and recommendations with interested parties prior to finalization of the work.

2.6.1 Field Trips

Four field trips were conducted:

(a) The initial field trip was conducted in August 1992. Discussions were held with personnel from numerous government agencies and commercial companies. Consultations were held with the following:

United States Agency for International Development
United States Embassy
DOE (then Office of Energy Affairs)
Energy Regulatory Board
Department of Finance - Government of the Philippines
Office of Environmental Management - Govt of the Philippines
National Economic Development Agency
International Monetary Fund
Asian Development Bank
The World Bank
Petron Corporation
Pilipinas Shell Corporation
CalTex (Philippines) Inc.
Philippine National Oil Company
National Power Corporation
Center for Research and Communications
Trans-Asia Oil and Mineral Development Corporation

Through these consultations, a better understanding of the Philippine refining and marketing industry and the rule and practices of its regulations was obtained. The concerns of both those regulated and the regulators were explored. The financing institutions gave insight to their interests. Valuable perspectives of all those interviewed were obtained.

During this trip, DOE, through USAID/Manila, requested that a preliminary partial report be completed and presented as soon as possible so that additional insight could be gained by the Philippine authorities prior to the World Bank's decision on loan policies to the Philippines.

(b) The second field trip was of a technical nature. The team visited the Caltex and Shell refineries in August, but was unable to visit the Petron plant site due to the volcano activity. Extensive discussions were held with technical and operations management of each of the three companies, and a considerable amount of records and operating data and history was supplied by the companies for review and analysis.

(c) A third field trip, outside the original scope of work, was made in September, 1992 to present very preliminary observations of the

K&M team to DOE and others designated by DOE. These presentations served to increase the knowledge of the participants of the industry and regulatory practices, policies and problems. They were also an instrument to express and define concerns which were to be addressed in the subsequent work.

(d) The draft of the final report was discussed with all interested parties during the last field trip, in the first quarter of 1993. The results of these discussions were incorporated in the final report.

2.6.2 Modeling

Linear Program (LP) models were developed for the Philippine refineries based on technical data obtained from each of the refining companies, correlations of yields for each of the processing units, and assays of crudes processed. These models were then calibrated to approximate yields actually realized by each refinery when processing specific crude slates. Several LP runs were made to ascertain the yields which could be expected when processing varying slates of crude to more closely meet the desired demand. LP runs were made to determine the incremental cost of producing each of several products, and to evaluate future production capabilities based on planned expansions.

Computer spreadsheet models were developed to accomplish the following:

- Represent the administration of the OPSF, determining results of varying practices in administering the fund;
- Conduct financial data searches to obtain economic results of non-Philippine refining and marketing companies for comparison purposes leading to development and comparison of theoretical refining margins at locations throughout the world with those of the Philippines; and
- Compare actual Philippine distribution costs with the respective ERB allowances for each terminal from each of the three companies. Analysis was made of the changes required to match the allowances with actual costs.

Extensive research through use of technical, financial, private and public libraries was conducted to obtain data on correlations, financial performance, prices, regulatory policies of other countries, and supply/demand data.

All of the LP models, the spreadsheets, and their manuals (whenever applicable) were made available to DOE for possible future use and analysis. Training on the use of these models was provided to DOE personnel during the last field trip. DOE was also provided with the software (licensed to its name) needed to run the LP models.

Table 2-1

DESCRIPTION OF PROJECT TASKS

A. Phase 1 — Refinery Characterization and Implementation Report

Task 1 — Home Office Preparation and Team Mobilization

- Finalize needed questionnaires/information sheets for information requirements on refining, distribution, and marketing and oil regulations
- Identify sources for comparative processing operations and industry cost data
- Identify requirements for modeling and analysis tools, and information requirements for those tools to be used in the study
- Prepare outlines for discussions with Philippine sources on policy and pricing
- Hold team planning and organization meeting in Washington, DC to finalize tasking requirements

Task 2 — Data Collection on Overall Structure & Regulatory Framework for Philippine Refinery Sector

- Determine institutional framework and legislation for the downstream sector of the petroleum industry
- Identify data sources
- Assign responsibility for data collection

Task 3 — Conduct Refinery Survey Visits with Special Emphasis on the Operating and Energy Efficiencies of the Various Process Units

- Review available unit configuration, process yields, processing costs and product specification data from refinery
- Also review data on crude distillation units, catalytic reforming complex, and fluid catalytic cracking units

Task 4 — Perform Comparative Analysis of Processing Facilities and Operations of Selected Petroleum Refineries, including Recommendations for Future Processing Facilities

- Analyze and compare processing operations of Philippine refineries with comparable refineries in other world areas
- Define long range strategic issues for Philippine refineries

Task 5 — Prepare Preliminary Cost Estimates for Potential Implementation Strategies

- Develop long range strategy, including future process facility plans
- Develop various implementation scenarios
- Develop cost estimates based upon experienced cost in the Philippines

Task 6 Preliminary Financing Structure

- Develop a funding matrix with respect to the implementation scenarios

Task 7 Prepare Phase 1 Report of Present Preliminary Findings

- Discuss with interested parties in the Philippines, all the developed information and supportive backup data gathered during the process
- Prepare and distribute report

B. Phase 2 Sector Wide Economic Cost Structure and Pricing Analysis and Institutional and Regulatory Recommendations

Task 8 Refine Database on Cost Structure for Each Stage of the Refining, Distribution and Marketing Process

- Requirements and costs for operation, maintenance (labor and materials), utilities, catalyst, chemicals, and allocated costs
- Define relationship of cost to unit throughput
- Compare cost to industry (where costs are available)

Task 9 Analyze the Cost Structure & Identify Key Factors Affecting Petroleum Costs in the Philippines

- Identify the elements of costs for petroleum products
- Determine change in cost components as function of feedstock quality
- Determine change in product cost with changes in major cost elements
- Determine marketing and distribution costs as function of product type, market sales channel, and market sector
- Identify investment costs

Task 10 Compare Material & Energy Balances Over the Practical Range of Operating Levels

- Determine yield and quality data as function of feedstock properties and unit severities, or tie base unit operations to general unit correlation.

Task 11 Define Appropriate Cost Indicators

- Combine data developed in Tasks 8 through 10 for total cost structure analysis
- Analyze data on Philippine and comparative world refining and marketing operations to develop standards for refining various feedstock types to various product slates
- Recommend cost indicators for feedstock-to-product conversion and for distribution and marketing

Task 12 Recommend Appropriate Fiscal and Legislative Measures to Encourage Refinery Efficiencies

- Discuss with the Philippine responsible agencies potential benefits of alternative policies for improving refinery operating efficiencies
- Outline what legislation changes would assist in obtaining the above benefits

Task 13 Recommend Appropriate Pricing Policies Between Refineries, Retailers, and Consumers

- Review with appropriate Philippine authorities, the current policies affecting pricing of product, and sales to distributors, retailers and consumers
- Discuss the objectives of pricing policies
- Develop and review pricing policy alternatives, including partial and complete deregulation
- Recommend alternative for pricing policies

Task 14 Recommend Methodologies for Determining Transfer Pricing

- Develop and demonstrate methodologies for determining transfer prices (modeling required)
- Based on analysis and policy objectives, recommend transfer pricing methodology that can be implemented by interested agencies in the Philippines

Task 15 Recommend Appropriate Import Tariffs for Selected Petroleum Products

- Determine the current tariff regulations for crude and product imports
- Discuss with Philippine officials and refiners/marketers the state of crude and product imports and exports, trends and concerns
- Discuss the policy objectives of tariffs
- Recommend tariff policies for each product

Task 16 Determine End User's Capability to Bear Recommended Prices

- Analyze the impact of prices, at increasing levels, on the various using sectors (i.e. transportation, commercial, residential, etc.)
- Identify the segments of using sectors and their ability to bear increasing price levels
- Analyze the potential impact of pricing

Task 17 Recommend Appropriate Institutional Arrangements for Monitoring Refinery Performance

- Determine current government reporting requirements for refining and monitoring activities
- Discuss policy objectives and current regulations affecting refinery operations, financial performances, environmental issues, and energy information reporting
- Define petroleum refinery performance objectives
- Recommend monitoring, reporting or regulatory changes

Task 18 Identify Specific Areas Where Deregulation of Selected Industry Operations is Deemed Most Beneficial

- Review policy objectives, current oil refining and marketing sector performance and efficiency, and current industry regulations
- Determine economic benefits of removal of various regulations
- Analyze the pros and cons of regulation
- Identify areas where deregulation is recommended

Task 19 Develop Associated Deregulation Guidelines & Corresponding Timeframe for Implementation

- Based on the results of Task 18, develop guidelines and timeframe for deregulation implementation

Task 20 Measures Economic Benefits of Proposed Deregulation & Make Final Presentation of Phase II Findings and Recommendations

- Discuss with the interested parties in the Philippines all the developed information and supportive backup data gathered during the Task 8 to 19 process
- Prepare and distribute report

3 WORLD OIL MARKETS

This chapter provides a brief overview of the major trends in world crude oil and refined product markets, including an analysis of the following:

- Crude Price Trends
- Refined Product Trends
- Crude and Product Price Differentials
- Regional Variations In Product Markets
- Refinery Facilities In Regional Oil Markets

3.1 Crude Price Trends

The crude market over the past twenty years can be described in terms of the market of the seventies and the market of the eighties. In the 70's, The Organization of Petroleum Exporting Counties (OPEC) became a cohesive force controlling a high percentage of internationally traded crude oil. When this cohesiveness was combined with a second very important factor, tight supply, major price increases resulted. Despite this apparent "OPEC cohesiveness", during the two market spikes of 1973 and 1978/79 individual producers drastically increased prices as crude buyers, in panic, were repeatedly willing to pay the escalating prices based on anticipation of even higher prices in future weeks. The timing of the price spikes occurred when an already tight supply was further tightened by political events, such as the Arab Embargo of 1973 and the Iranian Revolution of 1978/79, which limited oil exports to certain countries and shut off additional production.

By the beginning of the 1980s, the crude market situation had begun to change. Declines in oil demand resulting from the price increases of prior years and significant increases in non-OPEC production volumes brought about a decade of crude supply surpluses and declining prices as shown in Figure 3-1. OPEC members met repeatedly to set production quotas, but the weight of excess supply progressively eroded prices with a final sharp decline in 1986.

During the same decade, the same types of political events that had produced the upward price movements of the 1970s occurred without any price increases that could be sustained over more than a period of a few months. During the last 20 years, the supply tightness, or percent utilization of production capacity, has been accepted by many crude market watchers as an important factor in determining when crude market price increases or decreases might occur (Figure 3-2).

During the 1990's most forecasters see crude supplies tightening once again and are projecting growth of crude prices on a constant dollar basis. These crude price increases will most likely occur after 1995. The crude price forecast made by the U.S. DOE is shown in Figure 3-3. This forecast is similar to many in projecting future crude prices in the form of smoothly increasing curves. It is more likely that most crude price increases will occur in the form of short term price spikes, which became a pattern in the late 1980's. The difference will be that prices won't drop all the way back down to pre-spike levels at the end of the spike. It is unlikely that major price spikes like those of the 1970's will recur; producers may realize that consumer countries will be able to effectively use strategic petroleum resources to curb panic buying during moderate short-term market tightness.

Figure 3-1

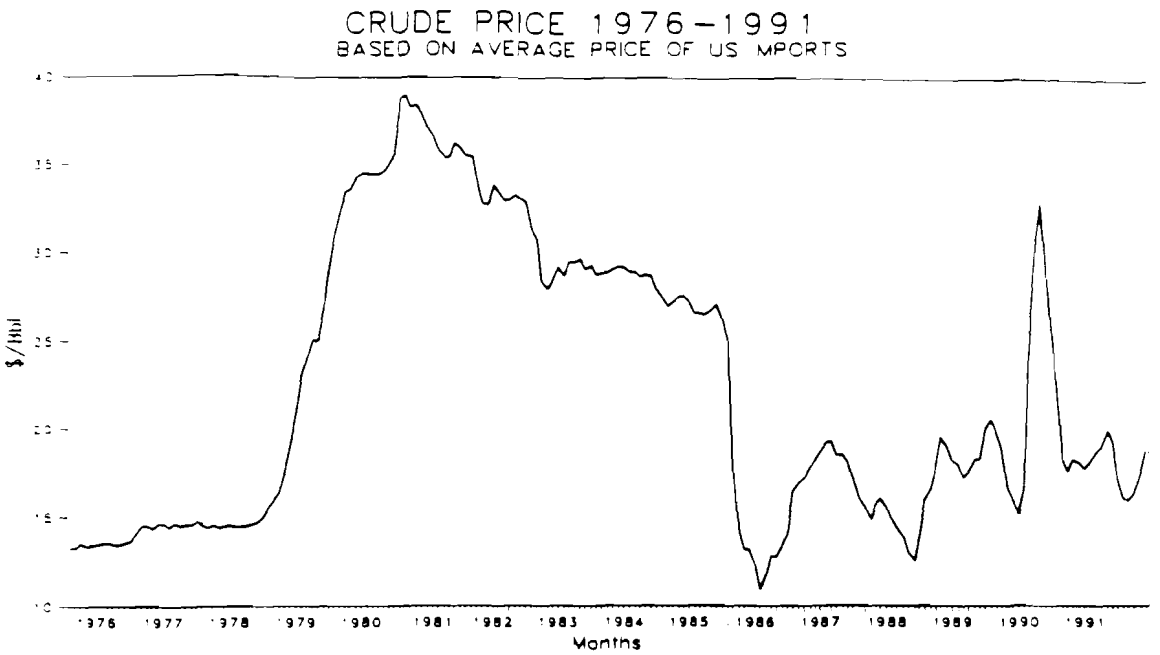
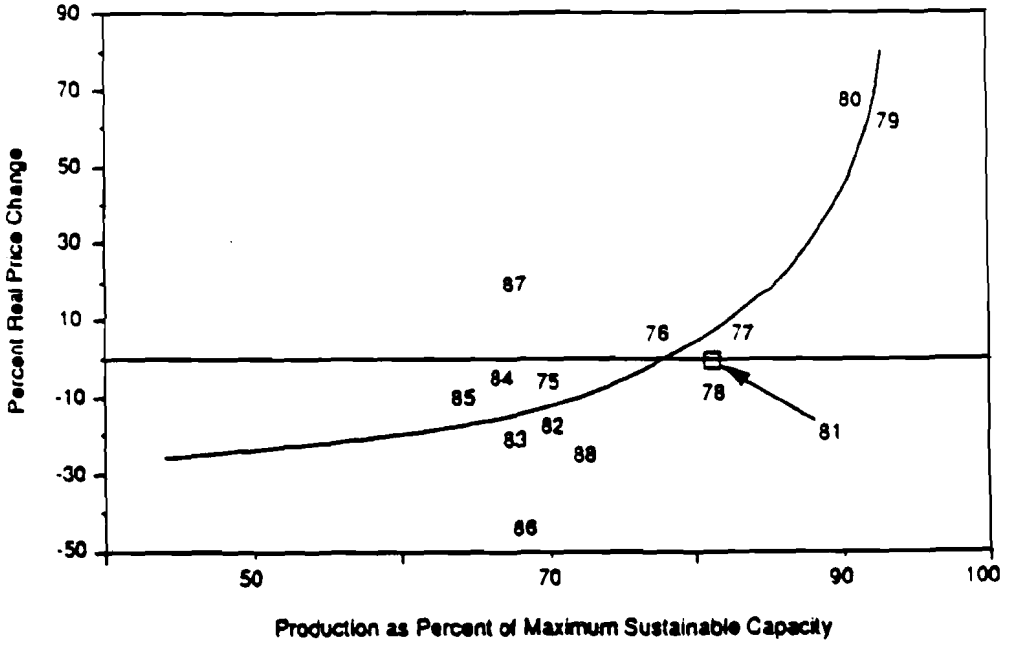


Figure 3-2
OPEC Price Reaction Function EIA Data, 1974-1988

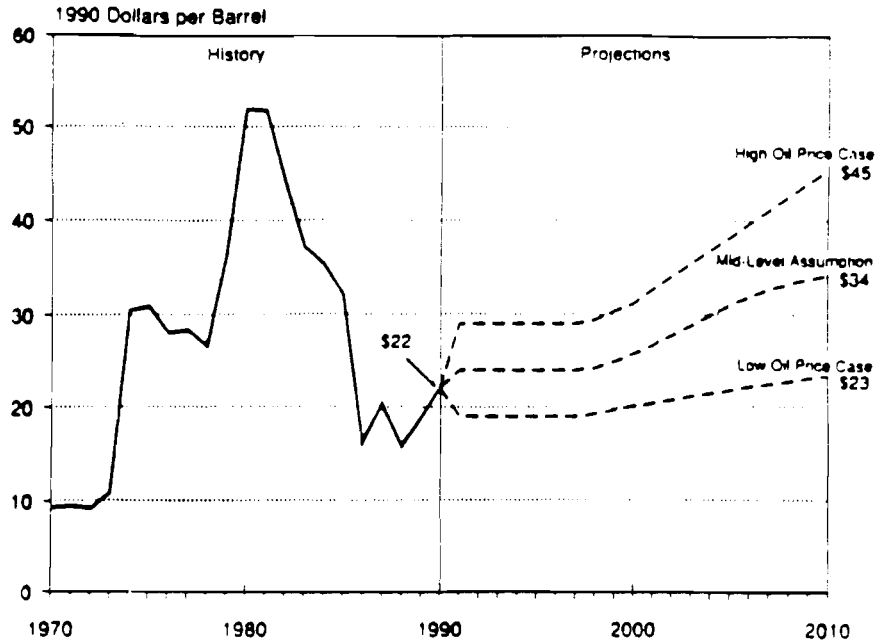


From the Energy Information Administration's Oil Market Simulation Model

BEST AVAILABLE COPY

34

Figure 3-3
U.S. Refiner's Acquisition Cost of Imported Crude Oil, 1970-2010



Sources: History: Annual Energy Review 1989 (May 1990), EIA Annual Energy Outlook 1991

3.2 Trends In Refined Products Markets

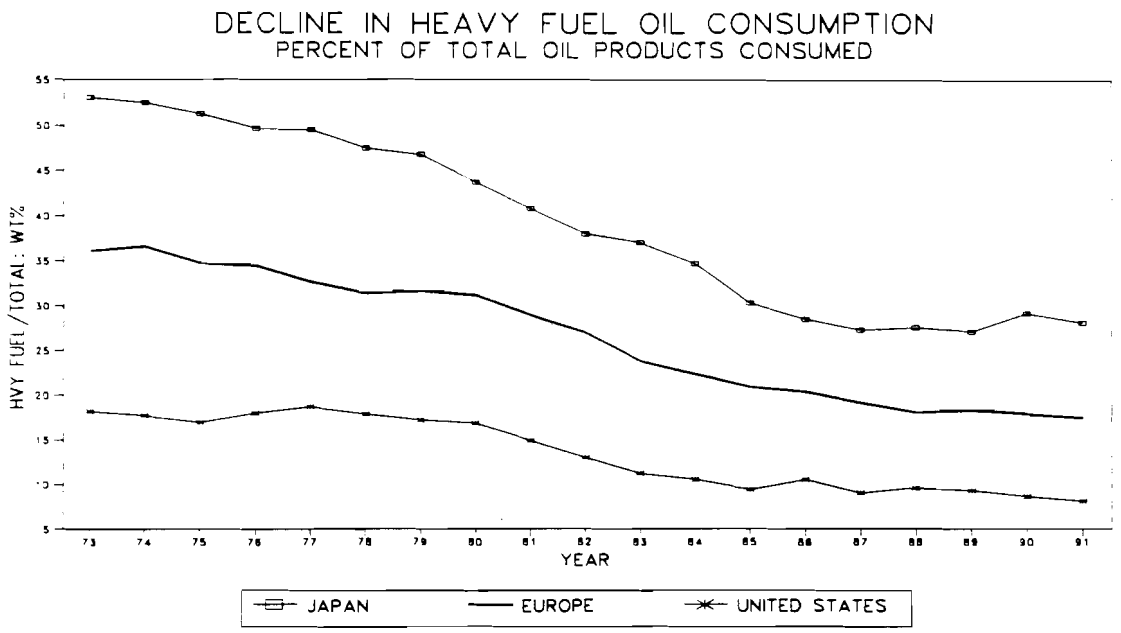
The most prominent change in the refined product markets over the past twenty years has been the decline in demand for heavy fuel oils. Heavy fuel oil sales volume in 1991 in the major refined product markets of Europe, United States, and Japan were only about half of the 1975 volumes, Figure 3-4. That decline in heavy (or residual) fuel oil sales meant that refiners have had to drastically reduce the volume percentage of heavy fuel oil produced as shown in the figure. The primary reason for the decline in heavy fuel oil volume has been price competition in the sectors in which heavy fuel oil is sold. Heavy petroleum fuel oils compete in the boiler market against coal, gas, biomass, etc. As crude prices rose in the 1970's, heavy fuel oil prices became less competitive and market share declined. The impacts on crude suppliers and refiners of the decline in heavy fuel demand have been:

- Increasing price differentials between light and heavy crude
- Increasing price differentials between light and heavy products (i.e. gasolines and middle distillates versus heavy fuel oil)
- Installation of heavy oil upgrading facilities in refineries

The only other refined product that experienced a similar declining market share as a result of rising crude prices was middle distillate fuel in the residential/commercial heating market, primarily in the US and Europe where there is strong competition from natural gas. However, the loss of middle distillate sales in these markets has been countered by sales

gains by middle distillate products in other market sectors.

Figure 3-4



The other major area impacting the refined product markets has been changing product quality requirements resulting from hightened environmental awareness and the ensuing improvement efforts. These changes have affected many products in the past two decades, including:

- Reduction or total elimination of lead from gasoline
- Reduction in sulfur allowed in all fuel products
- Stricter environmental requirements for refining plant operations

Lead has either been totally removed or reduced in gasoline products in most countries around the world. The octane requirements formerly achieved by the addition of Tetra-ethyl lead (TEL) are now being achieved by:

- Increased use of reforming
- Increased reformer severity
- Addition of alkylation and isomerization capacity
- Addition of oxygenates to gasoline products

BEST AVAILABLE COPY

36

The sulfur content permitted in oil products has been reduced in many countries; progressively lower limits continue to be imposed. The cost of reducing sulfur content increases exponentially as the boiling range and molecular weight of the crude oil fraction increases. The imposition of lower sulfur limits for heavy fuel products in some areas has contributed to the decline in heavy fuel oil demand discussed earlier.

In the future, the impact of changing environmental requirements on refined products may have an even greater impact on the oil markets. In the US, requirements for gasoline products are now specifying hydrocarbon composition, with upper limits on aromatic and olefin contents and lower limits on oxygen content. Hydrocarbon limits are also affecting diesel, and the continuing decrease in sulfur limits affects many products.

Air, water, soil and waste environmental regulations on refinery plant operations are also tightening. This adds to refining cost, and hence must become a component of increased product cost and price.

3.3 Crude and Product Price Differentials

Oil product price differentials are driven by how well the individual oil products compete in the market and by the cost of production. It is a matter of supply and demand curves but it is complicated by three aspects of the market interactions: i) product market, ii) competition on the world market for crude to supply different product-specific domestic markets, iii) distribution of investment in new refinery facilities. Product market can be illustrated by using heavy fuel oil as an example. When crude prices rose in the 1970's, heavy fuel oil in the US market appeared to be priced much higher than coal and natural gas (based on average prices). In reality, however, transportation costs of coal and gas to some areas were very high, resulting in prices much higher than the average. In other areas, coal and gas were not available at all. In some cases the fuel buyers could only use coal or gas if they made a capital investment to change combustors. In the long term, the extended availability of coal and gas provided incentive for some users to replace their combustion facilities -- as a result the demand curve shifted creating downward pressure on heavy oil price increases, and reducing its market share.

US refiners faced a problem with the bottom of the barrel: production of heavy fuel oil products was unattractive and trends indicated that the situation would worsen in the future. Refiners had two options to change their heavy fuel production, add facilities to convert the bottom of the barrel to lighter products or "upgrade" facilities and alternatively, purchase more light crudes containing less heavy material. In two important ways, US refineries were different from other buyers of international crudes. First, limits on product sulfur content were the most strict in the world; in some areas only 0.3 wt% S product could be burned. Second, US refiners were already producing less heavy fuel than refiners in other parts of the world.

The second and third aspects of the complications of market interaction can be stated in terms of the example of the US refiner. Refiners, who have somewhat different domestic product markets, compete on the same world market for international crude barrels. From the oil economics viewpoint the question becomes which refining region is buying the incremental barrel of each type of crude and hence setting the differential price. The third complication involves the investment in new refinery facilities. Installation of facilities to convert more heavy crude bottoms to light product was not limited to the US; European refiner could conceivably convert bottoms less expensively than US refiners and let the

high-priced, low bottoms content (light) crudes they had been using flow to the US market.

Many US refineries invested heavily in facilities to handle heavy high sulfur crudes, but those investment dollars earned a very poor return due to less than anticipated growth in light-heavy crude and product price differentials. European investors in Fluid Catalytic Cracking (FCC) capacity did much better. The US bottoms processing investors' poor return resulted from focusing far too heavily on the US market, and the fact that the unexpected decline in crude prices dampened the rate of decline of heavy fuel oil demand.

This background discussion demonstrates that product price differentials in the Philippines can be indirectly affected by the impact that product market trends and refinery facility decisions in the US, European and other world markets have on crude price differentials. The volumes of refined products moved in international markets are much smaller than the volumes of crude oil, but product imports and exports can also be important factors in determining price differentials in a market. The marginal barrel can be an import or an export. There can be variation in product price differentials in different refining markets, but crude price differentials, transportation costs for crudes and products, and the price and availability of import and export products all combine to determine the limits of that variation.

The historical trends in crude and product price differentials are reviewed in the following series of figures. In Figure 3-5, the light-heavy product price differential is seen since 1986 in terms of gasoline and heavy, high sulfur, fuel oil (resid) prices in the US. After 1986 crude prices were fairly constant, there has been an increasing differential in prices. Light and heavy product prices for the same period are shown for the Singapore market in Figure 3-6. The Singapore plot shows both major light products: gasoline and diesel (middle distillate). On average, gasoline is higher priced than diesel, but variations in seasonal demand peaks and competition in different markets produce different price fluctuation patterns for these light products.

While frequently referring to crude and product price differentials in market behavior analyses, many forms of relative prices are examined: differences, ratios, and both in terms of current dollars and in terms of constant dollars. In Figure 3-7 the ratio of the price of heavy, high sulfur, fuel oil to crude price is shown. The following example illustrates the relationship between differences and ratios: assume that the price of heavy fuel was 0.7 times the crude price and gasoline 1.2 times the crude price. If crude price doubled from 20 US$/bbl to 40 US$/bbl, then the price of heavy fuel would jump from 14 US$/bbl to 28 US$/bbl and gasoline would go from 24 US$/bbl to 48 US$/bbl. The <u>difference</u> between gasoline and heavy fuel doubles from 10 US$/bbl to 20 US$/bbl, while the <u>ratio</u> remains constant.

Figure 3-5

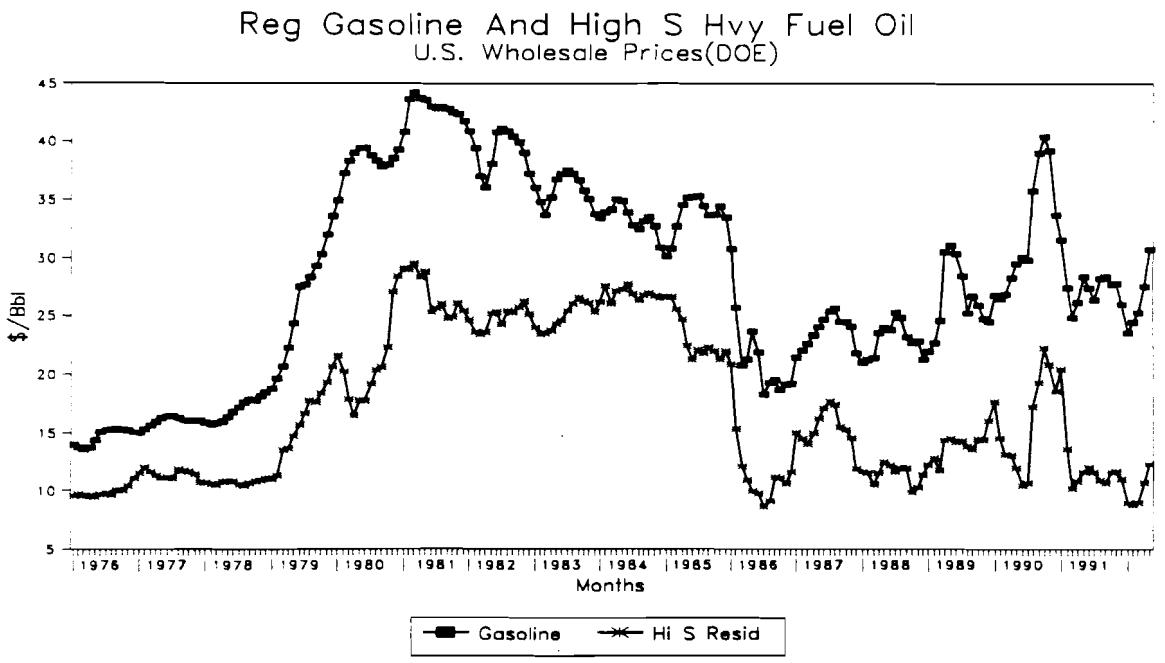
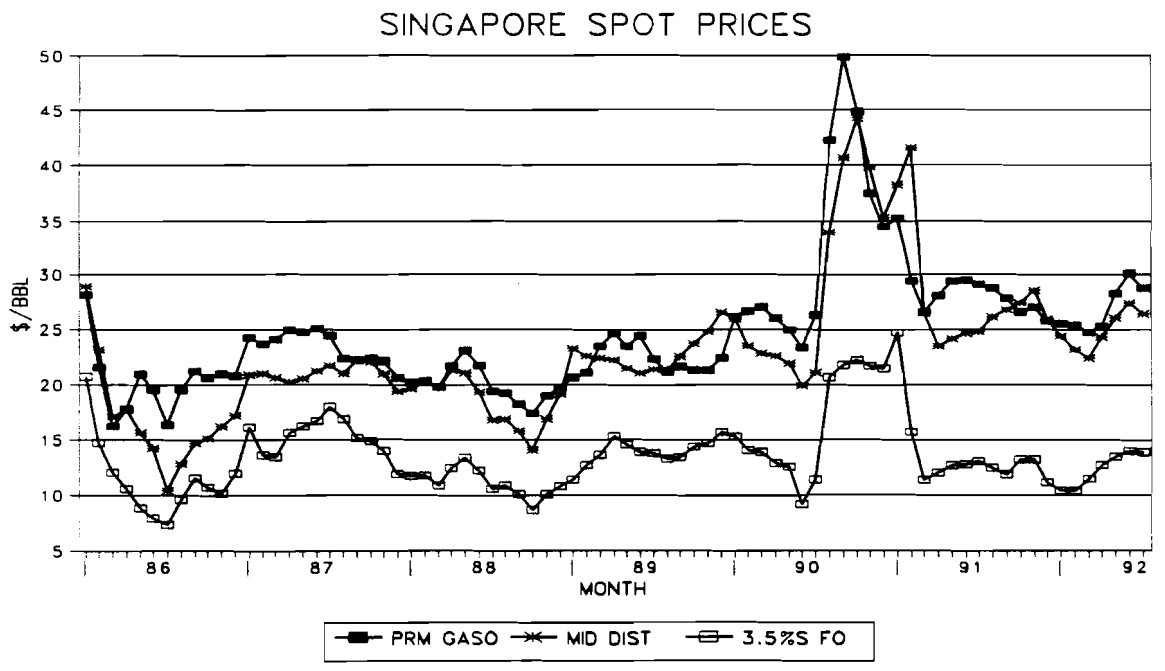
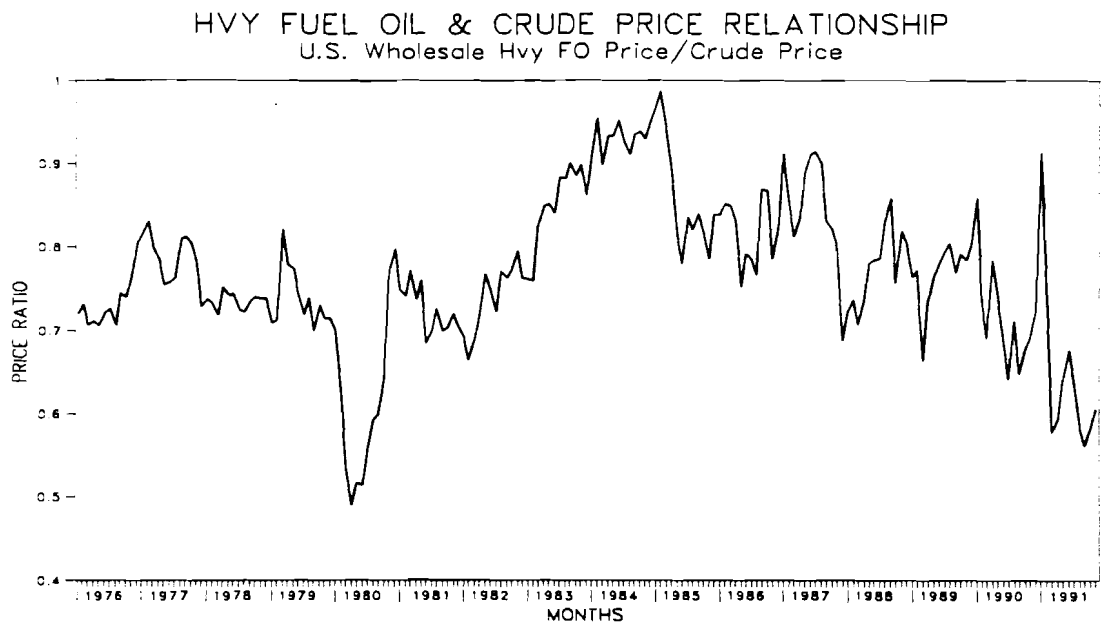


Figure 3-6



BEST AVAILABLE COPY

Figure 3-7



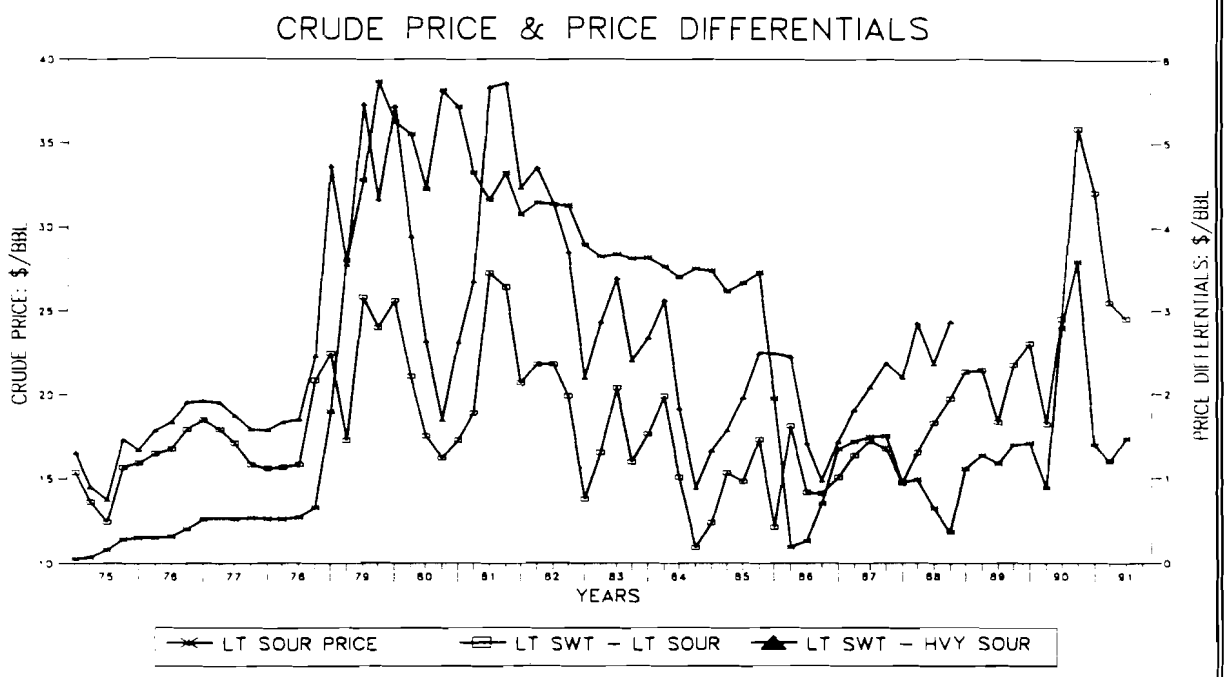
The heavy fuel oil to crude price ratio of Figure 3-7 can best be explained by breaking the time span into three periods: 1976 - 1982, 1982 - 1986, and 1986 - 1992. From 1976 - 1982, heavy oil demand was declining, but the price ratio remained fairly constant until the major price rise of 1979/80. The ratio did recover to about .7 by 1982, when the effect of equipment additions on both supply and demand were felt. Refiners installed equipment to reduce heavy oil production, and users who had easy access to more economically competitive fuels made equipment changes to facilitate the fuel switch.

From 1982 to 1986, there was a good heavy fuel market; decline in demand occurred without any excess supply appearing because of the refinery conversion facilities coming on stream, and the price ratio rose as crude prices declined. From 1986 to the present, the ratio has been falling: heavy oil prices, even with crude prices at 20 US$/bbl, are not competing well against coal and gas, and demand is still declining but excess conversion capacity is gone.

In Figure 3-8, the light-heavy crude price differential is plotted, and the same pattern as that of the light-heavy products differential is shown. It grew until 1982, declined from 1982 to 1986, and has been increasing since 1986.

BEST AVAILABLE COPY

Figure 3-8



3.4 Regional Variations In Product Markets

The breakdown by product group is shown in Table 3-1 and summarized in Table 3-2 for some of the world oil product markets. A more detailed breakdown by year, product and region is shown in Table 3-4 at the end of the chapter, page 3-13.

Table 3-1
1991 SHARE OF TOTAL PRODUCT (Wt%)

	USA	OECD-Europe	Japan	Non-OECD Asia
Gasolines	42.1	26.2	21.3	18.3
Middle Distillates	29.1	40.5	33.1	38.8
Fuel Oil	8.0	17.4	28.0	29.6
Other	20.8	15.9	17.6	13.3
Total	100.0	100.0	100.0	100.0

Heavy fuel oil demand, as a percent of total refined product demand, is highest in Asia. OECD -Europe has the highest middle distillate demand, but the relative proportions of gasoline and middle distillate are also factors in determining the difficulty in producing the balance of light products. In Non-OECD Asia, middle distillate demand volumes are more than double gasoline volume. The growth rates for the same world oil market areas are given in Table 3-2.

Table 3-2
PERCENTAGE DEMAND GROWTH - 1981-91

	USA	OECD Europe	Japan	Non-OECD Asia
Gasolines	+ 9.6	+ 23.0	+32.2	+104.0
Middle Distillates	+13.0	+ 14.1	+ 35.3	+ 65.7
Fuel Oil	- 43.7	- 40.0	- 24.1	+ 29.8
Other	+ 16.1	+ 8.3	+ 34.7	+ 90.7
All Products	+ 3.8	- 0.5	+ 0.5	+ 60.8

As can be seen, overall product growth in the non-OECD Asian countries is higher than in any other world region. Gasoline growth in the period has been more rapid than middle distillate growth, which indicates that it is not getting more difficult to make the balance of light products. While heavy fuel oil demand is growing in terms of overall volume, it declined from 36.6% of the product barrel in 1981 to 29.6% in 1991.

3.5 Refining Facilities in Regional Oil Markets

As can be seen in Table 3-3, the Asia/Pacific region has less conversion capacity (cracking and thermal processing) than Western Europe and North America. More of the conversion capacity that does exist in the Asia/Pacific region is geared to making gasoline rather than distillate. This is due to the existence of the FCC units in Japan. Of the large refining areas in the region, Singapore is most oriented to distillate production. Indonesia has some FCC cracking capacity and South Korea has virtually no conversion capacity at all.

Table 3-3
REGIONAL LOOK AT WORLDWIDE REFINING CAPACITY
(Downstream Processing as % of Distillation Capacity)

	No. of Refineries	Crude Distillion 10^3bbl/d	Vacuum Distillion	Catalytic Reformin g	Catalytic Hydro crack	Catalytic Cracking	Thermal Procs'ng
Asia/Pacific	126	13,359	23.2%	9.7%	2.6%	8.6%	3.8%
Western Europe	118	14,383	36.1%	15.5%	3.2%	14.0%	11.4%
E. Europe & CIS	89	12,873	16.1%	2.3%	0.5%	4.1%	N.A.
Middle East	41	4,943	26.2%	10.7%	5.5%	4.3%	N.A.
Africa	46	2,939	13.3%	11.8%	1.2%	5.9%	N.A.
North America	217	18,605	43.1%	22.2%	7.8%	31.3%	10.7%
S. America & Carib	75	6,047	43.2%	5.7%	1.2%	16.5%	N.A.
TOTAL	712	73,149	32.8%	12.5%	3.7%	14.9%	

3.6 Summary and Recommendations

World crude oil prices have gone through several transitions over the past twenty years. In the 70's the Organization of Petroleum Exporting Countries (OPEC) became a cohesive force due to its control of a very large part of crude oil production during a period of tight supply. Price spikes resulted from political events which eventually led to new price levels.

The much higher price of petroleum brought about energy conservation, fuel switching, and increased exploration throughout the world. This ultimately resulted in surplus supply and a significant drop in prices in 1986. Political events since then have caused price spikes but all were short lived due to excess production capacity. Most forecasters anticipate higher prices in the future. It is anticipated that these price increases will follow a pattern of spikes (resulting from political or other unpredicted events) and declines, but to a higher plateau than was evident before each spike.

The most significant change over the period of 1986-1992 has been the decline in the demand for heavy fuels with 1991 volumes only about half of the 1975 levels. Fuel substitution and increased conversion of the heavy portion of crude to lighter products have decreased the fuel oil production to the lower part of the refined product slate.

The relatively reduced demand for fuel oil has resulted in increased price and ratio differentials, between light and heavy products, and between light and heavy crudes.

Other major changes over the past twenty years in the refined products markets have been the more stringent quality requirements to meet environmental improvement efforts. Lead has been completely removed in most gasolines and greatly reduced in areas where it is still permitted. Additional octane upgrading hardware is required to offset the octane boost

formerly provided by TEL lead. In addition, reformulation of gasoline, reduced sulfur specs for distillates and fuel oil, restriction of aromatic content of gasoline and diesel, as well as more restrictive regulations governing refinery operations have required massive investments and increased cost of refining crude into environmentally acceptable products.

World oil markets are more transparent than those of twenty years ago. Real crude and product prices tend to equalize throughout the world once adjusted for freight and other added costs. Disequilibrium in prices are short lived as sellers seek the higher markets and buyers seek the lower cost supply.

Table 3-4

REGIONAL CONSUMPTION - BY PRODUCT GROUP Million Tonnes

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
USA											
Gasoline	297.9	194.4	298.4	304.4	305.4	314.3	325.2	333.8	334.1	327.1	326.4
Middle Distillates	199.2	186.6	189.0	200.9	2.4	213.5	218.7	229.7	231.3	230.5	225.1
Fuel Oil	110.6	90.8	78.6	86.0	67.3	78.2	69.2	75.7	73.3	66.7	52.3
Others	138.3	133.7	138.9	145.6	144.2	145.3	154.2	154.2	153.9	157.2	160.5
Total USA	746.0	605.5	704.9	736.9	519.3	751.3	767.3	793.4	792.6	781.5	774.4
Canada											
Gasolines	31.3	28.4	27.3	27.2	27.7	29.2	29.2	28.3	28.7	28.4	27.4
Middle Distillates	25.0	23.1	21.6	22.0	22.2	22.6	22.8	24.2	25.1	24.0	22.4
Fuel Oil	11.2	9.8	7.7	6.8	5.6	6.4	7.1	7.7	9.4	8.7	7.7
Other	14.2	11.6	11.6	10.7	13.0	12.8	14.0	16.6	17.1	16.6	17.3
Total Canada	81.7	72.9	68.2	66.7	68.5	71.0	73.1	76.8	80.3	77.7	74.8
OECD Europe											
Gasolines	134.4	135.5	138.1	139.3	139.5	146.0	149.1	154.4	156.9	163.3	165.3
Middle Distillates	224.3	215.6	215.7	225.1	228.1	238.8	240.9	243.9	241.7	247.0	255.9
Fuel Oil	182.8	162.0	138.9	131.0	120.6	121.4	114.1	109.5	110.9	110.5	109.7
Other	92.7	88.5	91.3	92.9	89.8	94.3	95.7	100.3	100.7	101.1	100.4
Total OECD Europe	634.2	601.6	584.0	588.3	578.0	600.5	599.8	608.1	610.2	621.9	631.3
Japan											
Gasolines	39.8	38.6	39.5	41.1	41.5	43.1	44.4	46.7	49.4	51.0	52.6
Middle Distillates	60.6	58.0	59.6	64.2	63.6	66.6	69.5	76.8	79.2	78.7	82.0
Fuel Oil	91.2	78.8	76.4	75.4	62.4	59.2	56.9	61.8	62.9	70.6	69.2
Other	32.3	32.4	31.7	37.2	38.8	39.6	38.4	39.4	41.4	42.6	43.5
Total Japan	223.9	207.8	207.2	217.9	206.3	208.5	209.2	224.7	232.9	242.9	247.3
Australia											
Gasolines	13.1	13.4	13.1	13.5	13.5	13.4	13.5	14.0	14.5	14.7	14.6
Middle Distillates	9.8	10.1	9.6	10.2	10.4	10.9	11.5	12.1	12.6	12.9	12.8
Fuel Oil	5.6	4.4	3.8	3.8	2.9	2.6	2.5	2.5	2.7	2.4	2.3
Other	4.7	4.4	4.6	4.9	4.0	5.3	5.5	5.7	5.8	6.4	6.1
Total Australia	33.2	32.3	31.1	32.4	30.8	32.2	33.0	34.3	35.6	36.4	35.8
Asian Non-OECD											
Gasolines	34.8	34.7	36.2	38.0	38.0	41.4	46.6	49.3	54.1	66.8	71.0
Middle Distillates	90.9	92.5	95.1	98.9	104.4	112.9	114.5	125.2	135.3	140.5	150.6
Fuel Oil	88.4	85.0	86.2	84.5	86.4	88.8	92.7	102.3	110.0	111.0	114.7
Other	27.0	27.8	29.0	31.9	32.4	38.1	42.2	45.9	46.4	47.7	51.5
Total Asian Non-OECD	241.1	240.0	246.5	253.3	261.2	281.2	296.0	322.7	345.8	366.0	387.8
Non-Asian LDC's											
Gasolines	83.3	87.0	88.4	87.2	88.7	88.3	90.7	93.4	96.4	103.3	107.2
Middle Distillates	137.0	144.5	149.8	151.3	153.8	152.7	158.8	162.8	163.7	168.9	173.6
Fuel Oil	126.5	120.8	118.5	121.4	120.8	122.8	126.3	127.3	132.9	133.3	132.8
Other	60.3	64.3	65.6	65.6	72.3	75.1	78.2	81.4	82.2	90.2	89.2
Total Non-Asian LDC's	407.1	416.6	422.3	425.5	435.4	438.7	454.0	464.9	475.2	495.7	502.8
Total OECD & LDC's											
Gasolines	634.6	632.0	641.0	650.7	654.3	675.7	698.7	719.9	734.1	754.6	764.5
Middle Distillates	746.8	730.4	740.4	772.6	787.3	818.0	836.7	874.7	888.9	902.5	922.4
Fuel Oil	616.3	551.8	510.1	498.9	465.8	479.2	468.8	486.8	502.1	503.2	498.7
Other	369.5	362.7	372.7	388.8	394.5	410.5	428.2	443.5	447.5	461.8	468.6
Total OECD & LDC's	2367.2	2276.7	2264.2	2311.0	2301.9	2383.4	2432.4	2524.9	2572.6	2622.1	2654.2

Note:
'Gasoline' consists of aviation and motor gasolines and LDF (light distillate feedstock)
'Middle Distillates' consists of jet and heating kerosines, and gas and diesel oils (including marine bunkers)
'Fuel Oil' includes marine bunkers
'Others' consists of refinery gas, LPGs, solvents, petroleum coke, lubricants, bitumen, wax and refinery fuel and loss

Source: 'BP STATISTICAL REVIEW OF WORLD ENERGY' - June 1992

4 OIL PRODUCT PRODUCTION COST AND PRICING

Refineries use crude oils to produce an array of refined oil products. This chapter describes how it is possible to establish the relative cost of producing each of the individual products made by the refiner in this multi-product production process.

The cost of producing an individual oil product is not one specific value for a refiner; the cost of production changes as the volume percentage of production of that product changes. Generally, as the volume of a specific product increases, the more costly it becomes, because it means that the various materials (hydrocarbon molecules) in the crude oil must be broken apart, combined, or recombined to match the requirements of that product; the material that is easiest to convert is changed first and then the more difficult and more expensive are changed in progressive fashion. In any market, there are usually a number of refineries which have different types of processing units. Because of the different processing facilities, the relationships between production volume and production costs are different for the various refiners and, consequently, the relationships between production costs and product volume percentages also differ. One refiner may produce 20% gasoline and another may produce 35% gasoline; that may represent rational economic decision making by both refiners for the same set of refinery gate prices.

Economic decisions by refiners are made by analyzing the incremental or marginal barrel. Given refinery gate prices, is it more cost-effective for the refiner to produce one more barrel of gasoline and one less barrel of diesel, or 2 more and two less, etc? The refiners calculate production volume changes with cost changes in order to maximize refining profitability. Most often, the calculation tool used by refiners for analyzing economics to maximize refinery profits is a refinery linear programming (LP) model. Using an LP model, the refiner can optimally choose from many interacting decision variables (typically 50 -100 for most refineries) in changing incremental production volumes.

The cost to produce an incremental barrel of product from a refinery depends on the following operating cost factors:

- The relative prices and volumes of crude input to the refinery.
- The processing equipment utilization.
- The ability to vary operations - - cut points, unit operating severity, product specifications.
- The refinery's variable operating cost.

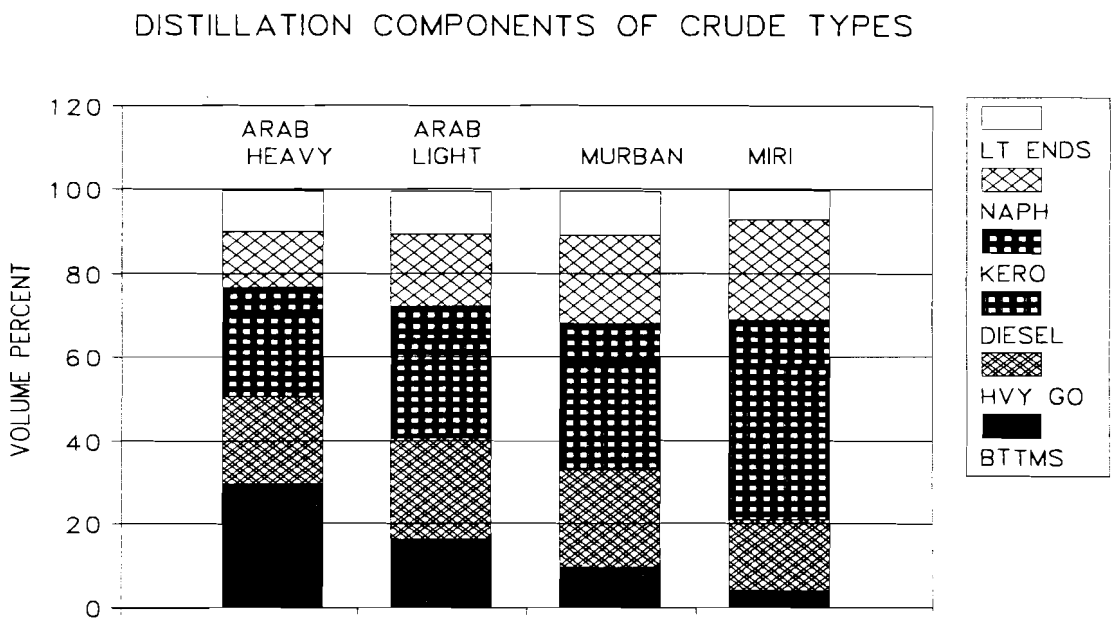
The cost to produce an incremental barrel may change by a very small amount or rather drastically over a range of volume changes. The degree of cost change depends on which of the above factors change. Each of these factors is reviewed to provide an understanding of how incremental production cost is determined in a refinery. Data for Philippine refineries will be used to illustrate the impact of these factors.

Refiners are constantly analyzing crude selection in an effort to maximize refining profits. Crude oils differ in many ways, the most prominent being the boiling range distribution of the material that makes up a specific crude as shown in Figure 4-1. The figure shows the four crude oils used in the marginal cost analysis described in this section. These crude oils range from Arab Heavy, a heavy crude which has 29.6% by volume of high boiling residual material and only 20.2% volume in the diesel fraction to Miri, a light crude which has only 3.7 vol% residual boiling range material and 37.6 vol% in the diesel boiling range. In addition to boiling range, crude oils differ in the types of hydrocarbon molecules in the boiling range which affect how easily they can be converted into final products, and in

46

sulfur and metals contents, which pose problems for processing and product quality.

Figure 4-2



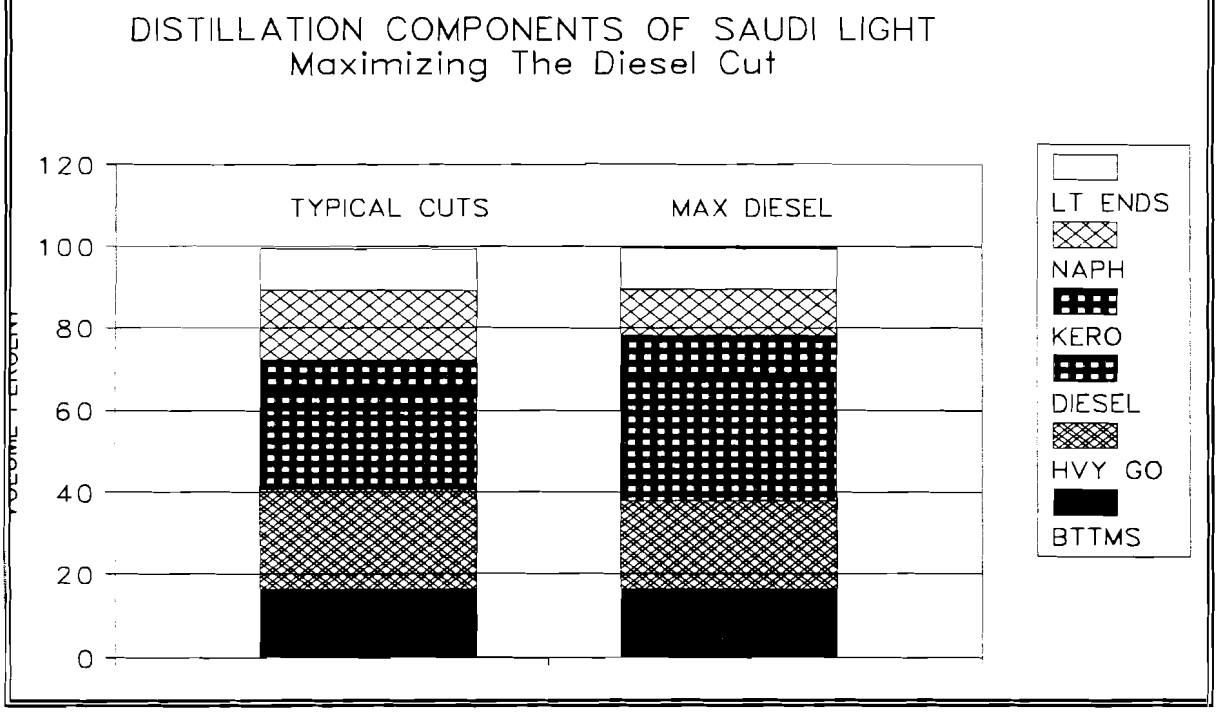
The refiner's product volumes will also change with the level of use of the various processing units which the refiner has available. Utilization of a downstream process unit (such as Fluid Catalytic Cracking Unit (FCC)) can be a function of the amount of feedstock available, which changes with crude selection; in addition, some feedstock can simply be diverted around the unit if there is no further demand for that unit's products.

A refinery can change a number of operating variables to change the mix of final products produced. When crude and downstream materials are separated by distillation, the refinery can change the temperature that marks the end of one stream and the beginning of the next higher boiling stream; this is referred to as a distillation "cut point". Some variations in cut points are usually allowed by the specifications on market products. For example, if a refiner wishes to increase gasoline production without changing the types of crude being input to the refinery, the cut points between naphtha and kerosene can be increased. That change will provide more reformer feed (the added heavy material at the top of the naphtha stream) and less kerosene. The refiner could also reduce the cut point on the crude distillation unit between the diesel stream and the heavy gas oil which will go to the FCC unit which will mean more gasoline production and less diesel fuel. Changes in cut points for a refiner to maximize distillate production are shown in Figure 4-2.

Changing operating conditions of processing units can change the relative volumes of products. While there are many operating variables such as reactor temperature, pressure, space velocity, etc., it is customary to group variable changes and refer to high severity and low severity or high conversion versus low conversion as alternative operating modes for processing units. In the cases analyzed in this study, the FCC unit in the Caltex refinery

can be operated between a low and high conversion level. At the higher conversion level, gasoline production is higher and diesel production is lower. The conversion levels for the FCC unit are based on the catalyst currently being used in the Caltex refinery. In the longer term, it would be possible to make added increases in gasoline productivity by replacing the present catalyst with a high gasoline yield FCC catalyst.

Figure 4-2



The variable operating costs change as crude inputs, processing unit throughputs, and severities change. These variable operating costs include fuel, utilities, and catalyst and chemicals for unit operations.

The cost of producing an incremental barrel of product can be determined using an LP model, which provides a simulation of the refinery production processes and costs, including the type of changes described in this chapter. An LP model is an optimizing model that analyzes all the possible changes simultaneously to determine the best solution, i.e. to produce the array of required products at minimum cost. Based on information gathered on Philippine refinery operations and documented in the "Cost Structure and Transfer Pricing For the Philippine Petroleum Industry: Technical Report" and from the use of additional crude assay information and process correlations, LP models of each of the individual refineries were developed (for detailed documentation, see "Models Documentation and User's Guide"). The use of process correlations provides the ability to estimate refinery operations beyond the extent of actual refining data, and also to account for the impacts of variation of the specific crudes charged to the refinery. The use of correlations and the individual crude assays are exceedingly valuable in analyzing incremental costs and many other types of refinery analyses, but there are limitations. For example, the cracking correlation was not used to estimate conversion levels for the Petron

refinery for two reasons. First, the Petron catalytic cracking unit is a Thermofor Catalytic Cracking (TCC) unit rather than an FCC unit; these units are similar but different enough to question the applicability of the correlation. Second, the cracking unit yield data reported at Petron is at very low conversion, below the level where use of the correlation is currently appropriate. Thus, the incremental cost analysis was carried out with the Caltex and Shell refinery models.

4.1 Analysis of Diesel and Gasoline Incremental Production Cost

Results of simulating a Philippine refinery with an FCC processing unit using an LP refinery model are shown in Table 4-1. In the case shown, 13,000 bbl/d of gasoline and an equal volume of diesel were produced from the refinery while charging 46,631 bbl/d of crude. As shown by the MIN column, the refinery was required to run at least 16,000 bbl/d of Arab light crude. The incremental values (INC-VAL) placed on these crudes are equal to the price, except for Arab Light which is valued at 17.58 US$/bbl which means the model could reduce cost by replacing some of the 18.00 US$/bbl Arab light crude with a combination of the other crudes.

The marginal costs of producing the incremental barrels of products are dependent on the relative prices of the different crude oils, the process unit limitations, and the variable operating costs which include fuel, utilities, and catalyst and chemicals. Variable costs are only those costs that vary or change as the volume throughput to the primary distillation and the other processing units change. There are other operating costs that the refiner must pay, such as personnel costs, but these are not included because they do not change with volume throughput. For example, whether the FCC unit is operated at 7,000 bbl/d or 10,000 bbl/d, the same number of operators and supervisory personnel are required. Thus, the marginal costs do not reflect the full cost of manufacture. However, the differences in incremental costs are a gauge of the differentials in market prices that would be needed to give a refiner economic incentive to provide products in the relative proportions shown in Table 4-1.

The marginal costs of producing gasoline versus kerosene, diesel, and fuel oil are taken from Table 4-1 and compared with the average product price differences on the Singapore spot product market in recent years:

	Philippine Refinery LP Model	Singapore Spot Market
Premium Gasoline - Kerosene (US$/bbl)	.79	.18
Premium Gasoline - Diesel (US$/bbl)	.92	1.76
Premium Gasoline - Hi S Fuel Oil (US$/bbl)	8.04	11.70

The purpose of this comparison is to begin to associate market price differentials and the refiners' differential cost of producing those products. As shown in both cases, premium gasoline is the highest priced product with kerosene and diesel being reasonably close in price. There is a major price difference between premium gasoline and heavy, high-sulfur, fuel oil.

Table 4-1

ANALYSIS OF MARGINAL COST TO PRODUCE GASOLINE AND DIESEL

Caltex Batangas Refinery — Run: MCC1

Refinery Crude Inputs	PRICE $/B	VOLUME MB/CD	MIN MB/CD	MAX MB/CD	INC-VAL $/B
Arab Hy (28.2API 2.80S)	15.400	8.655	0.000	No Lim	15.400
Arab Lt (34.4API 1.69S)	18.000	16.000	16.000	No Lim	17.580
Miri Lt (36.3API 0.08S)	21.000	10.643	0.000	No Lim	21.000
Murban (39.2API 0.81S)	19.050	11.332	0.000	No Lim	19.050
Total Crude		46.631			

Refinery Outputs

Products	PRICE $/B	VOLUME MB/CD	MIN MB/CD	MAX MB/CD	INC-VAL $/B
Refinery Flare	None	0.000	0.000	9999.000	0.00
Liquid Petroleum Gas	None	1.275	0.000	5.000	0.01
Premium Gasoline	None	9.750	9.750	14.000	21.75
Regular Gasoline	None	3.250	3.250	6.000	19.97
Naphtha Product	None	2.500	2.500	5.000	18.79
Reformate Product	None	1.000	1.000	5.000	25.65
Kerosene-Jet Fuel	None	5.400	5.400	8.000	20.96
Kero. Solvents	None	0.100	0.100	0.500	20.96
Naph. Solvents	None	0.100	0.100	0.500	18.79
Diesel Fuel	None	10.215	10.215	15.000	20.83
Diesel Fuel-Lo Sulf	None	2.785	2.785	5.000	20.83
No 6 Fuel Oil	None	9.000	9.000	20.000	13.71
No 6 Fuel Oil-Lo Sulf	None	0.500	0.500	5.000	19.08
Asphalt - Pitch	None	0.100	0.100	1.000	6.64
Total Product		45.975			

Process Unit Summary

Process Unit	CHARGE MB/CD	CAPACITY MIN MB/CD	CAPACITY MAX MB/CD
Atmospheric Distillation	46.631	0.000	71.000
Vacuum Distillation	15.897	0.000	19.500
Catalytic Reforming	4.957	0.000	7.000
Low Severity	4.957		
High Severity	0.000		
Catalytic Cracking	9.075	0.000	12.500
Low Conversion	3.249		
High Conversion	5.826		
LPG Treater	1.275	0.000	4.100
Naphtha Hydrotreater	7.559	0.000	12.500
Kero-Jet Merox Treater	5.528	0.000	11.000
Distillate Hydrotreater	0.003	0.000	16.000

The marginal costs for products change as the volume of production from the refinery changes. These changes were analyzed in a series of refinery model simulations in which gasoline volume was increased and distillate volume was decreased by an equal amount. In Figure 4-3, the marginal costs of producing gasoline and diesel are plotted. As gasoline production is increased, the cost of making gasoline increases and diesel decreases and vice versa. The plot shows a point where diesel becomes the higher cost product to produce as diesel production volume is increased. The final important point demonstrated by the plot is that at either end, when gasoline or diesel volumes get relatively high, the cost difference increases dramatically. This occurs when the refiner simply cannot make the balanced volume of products required (indicated by the MIN quantities) by changing crude mix, cut point, unit throughput, or severity. The very large price difference indicates that the refinery is approaching the point where the only way to make an incremental barrel of diesel is to run incremental crude and produce gasoline which has zero value because there is no market for that incremental barrel. In reality, the refiner can reach this point in terms of limitations, but the practical solution would be to purchase the incremental barrel of diesel rather than to produce it. Thus, the limit on the maximum incremental cost for gasoline or diesel is the outside purchase cost of that product from another refiner or acquired on an international market for import.

The cost factors that change to produce the increasing marginal cost of diesel production as gasoline volume increases are contained in Table 4-2 and are shown in Figure 4-4. When diesel production is at the low end of the production range, at 10,500 bbl/d, the refinery charges only 4.98% Miri crude; all of the available cracking feedstock are going to the FCC unit and are operating at high severity to maximize gasoline production. The plot of Figure 4-4 shows that a rise in marginal cost of diesel production is associated with an increasing use of the relatively expensive Miri crude and a decreasing use of the FCC unit. Ultimately, a point is reached where if more Miri crude is used, it is impossible to make the required fuel oil production (or to make the fuel oil requirement, excess gasoline or naphtha would be produced).

A slightly different picture emerges when variations in diesel and gasoline marginal production are analyzed in a refinery without an FCC unit (Figure 4-5). The FCC unit is a gasoline maker and without it the range of gasoline production is narrower because of loss of flexibility to expand gasoline volumes.

Table 4-2

ANALYSIS OF THE MARGINAL COST TO PRODUCE GASOLINE AND DIESEL IN PHILIPPINE REFINERIES

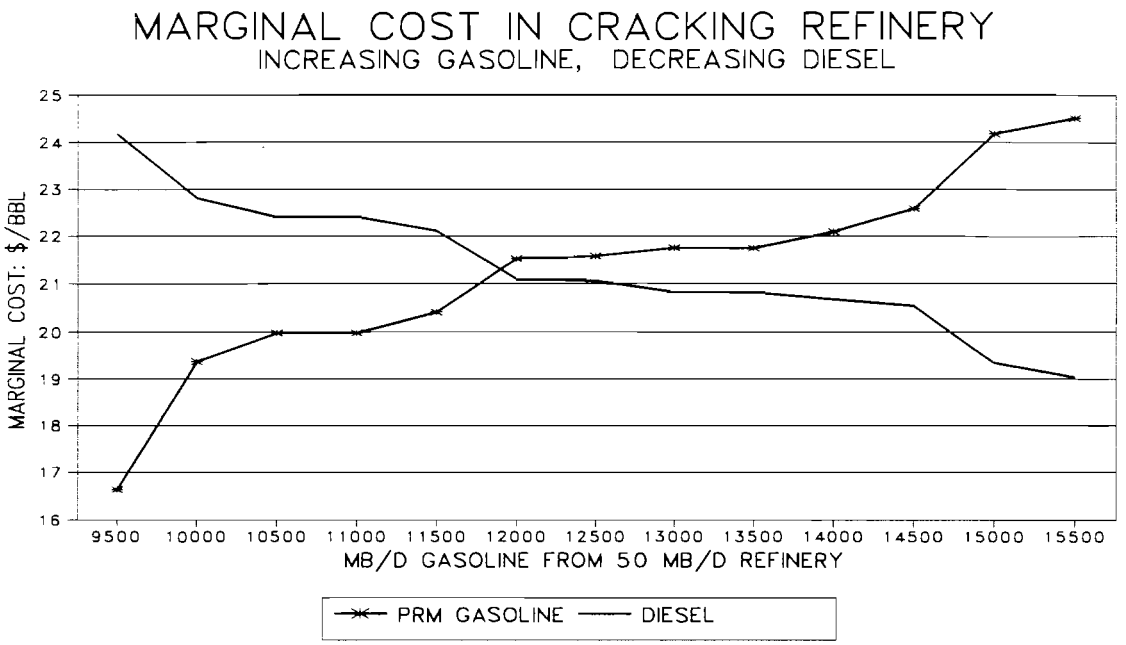
CALTEX

ARAB HEAVY B/CD	ARAB LIGHT B/CD	MUR-BAN B/CD	MIRI B/CD	TOTAL B/CD	PCT MIRI	CRUDE AVG $/B	PREM GASO B/CD	REGLR GASO B/CD	TOTAL GASO B/CD	GASO % CRD	DIESEL B/CD	DIESEL LOW S B/CD	TOTAL DIESEL B/CD	DIESEL % CRD	TOTAL PRODUCT B/CD	INC-VL PRM G $/BBL	INC VL DIESEL $/BBL	INC VL No 6 $/BBL	REFRM CHG B/CD	FCC CHG B/CD
9384	16000	0	20956	46340	45.2	18.83	7125	2375	9500	20.5	12985	3535	16500	35.61	45528	16.65	24.17	14.38	4901	6990
8973	16000	6127	15438	46538	33.2	18.83	7500	2500	10000	21.5	12572	3428	16000	34.38	45788	19.37	22.80	13.61	3924	7865
8360	16000	10709	11626	46695	24.9	18.52	7875	2625	10500	22.5	12179	3321	15500	33.19	45973	19.97	22.41	13.47	4109	8268
8406	16000	10577	11626	46609	24.9	18.52	8250	2750	11000	23.6	11786	3214	15000	32.18	45888	19.97	22.41	13.47	4393	8237
8683	16000	10275	11626	46584	25.0	18.50	8625	2875	11500	24.7	11393	3107	14500	31.13	45930	20.41	22.12	13.36	4309	8361
8762	16000	10170	11626	46558	25.0	18.49	9000	3000	12000	25.8	11000	3000	14000	30.07	45967	21.52	21.11	13.82	4164	8818
8857	16000	9436	11626	45919	25.3	18.47	9375	3125	12500	27.2	10608	2892	13500	29.40	45280	21.59	21.07	13.56	4700	8781
8855	16000	11332	10643	46630	22.8	18.46	9750	3250	13000	27.9	10215	2785	13000	27.88	45975	21.75	20.83	13.71	4957	9075
8671	16000	11324	10647	46642	22.8	18.46	10125	3375	13500	28.9	9822	2678	12500	26.80	45959	21.75	20.83	13.71	5457	9074
8653	16000	11604	10416	46673	22.3	18.45	10500	3500	14000	30.0	9429	2571	12000	25.71	45965	22.10	20.88	13.39	5921	9126
8601	16000	11841	10261	46703	22.0	18.45	10875	3625	14500	31.0	9036	2464	11500	24.62	45997	22.58	20.55	12.74	6234	9416
8014	16000	14703	8144	46861	17.4	18.41	11250	3750	15000	32.0	8643	2357	11000	23.47	46179	24.17	19.35	12.09	6306	10097
6515	16000	22370	2354	47239	5.0	18.29	11625	3875	15500	32.8	8250	2250	10500	22.23	46552	24.51	19.03	11.90	6253	10596

SHELL

ARAB HEAVY B/CD	ARAB LIGHT B/CD	MUR-BAN B/CD	MIRI B/CD	TOTAL B/CD	PCT MIRI	CRUDE AVG $/B	PREM GASO B/CD	REGLR GASO B/CD	TOTAL GASO B/CD	GASO % CRD	DIESEL B/CD	DIESEL LOW S B/CD	TOTAL DIESEL B/CO	DIESEL % CRD	TOTAL PRODUCT B/CD	INC-VL PRM G $/BBL	INC-VL DIESEL $/BBL	INC-VL No 6 $/BBL	REFRM CHG B/CD	FCC CHG B/CD
12798	16000	8401	17366	56565	30.7	18.49	5667	2833	8500	15.0	18474	1026	19500	34.47	55442	13.29	30.00	13.29	6755	
12907	16000	8848	16247	56002	29.0	18.44	6000	3000	9000	16.1	18000	1000	19000	33.93	54897	20.59	23.82	13.11	6717	
12982	16000	8980	15967	55909	28.6	18.42	6334	3166	9500	17.0	17527	973	18500	33.09	54798	20.80	23.80	12.99	7099	
13051	16000	9066	15704	55821	28.1	18.41	6667	3333	10000	17.9	17053	947	18000	32.25	54705	20.84	23.81	12.83	7467	
13727	16000	6027	17878	55632	32.1	18.44	7000	3500	10500	18.9	16579	921	17500	31.46	54500	22.81	22.67	12.99	7868	
13596	16000	6996	17054	55646	30.6	18.42	7334	3666	11000	19.8	16106	894	17000	30.55	54500	23.06	22.52	13.00	8331	
13502	16000	7759	16401	55662	29.5	18.40	7667	3833	11500	20.7	15632	868	16500	29.64	54500	23.09	22.50	12.97	8800	
13374	16000	8659	15655	55688	28.1	18.38	8000	4000	12000	21.5	15158	842	16000	28.73	54500	23.35	22.26	12.82	9275	
11434	16000	11842	14446	55724	25.9	18.47	8334	4166	12500	22.4	14885	815	15500	27.82	54500	30.00	10.00	9.52	9735	

Figure 4-3


MARGINAL COST IN CRACKING REFINERY
INCREASING GASOLINE, DECREASING DIESEL
MARGINAL COST: $/BBL
25
24
23
22
21
20
19
18
17
16
9500 10000 10500 11000 11500 12000 12500 13000 13500 14000 14500 15000 15500
MB/D GASOLINE FROM 50 MB/D REFINERY
PRM GASOLINE
DIESEL

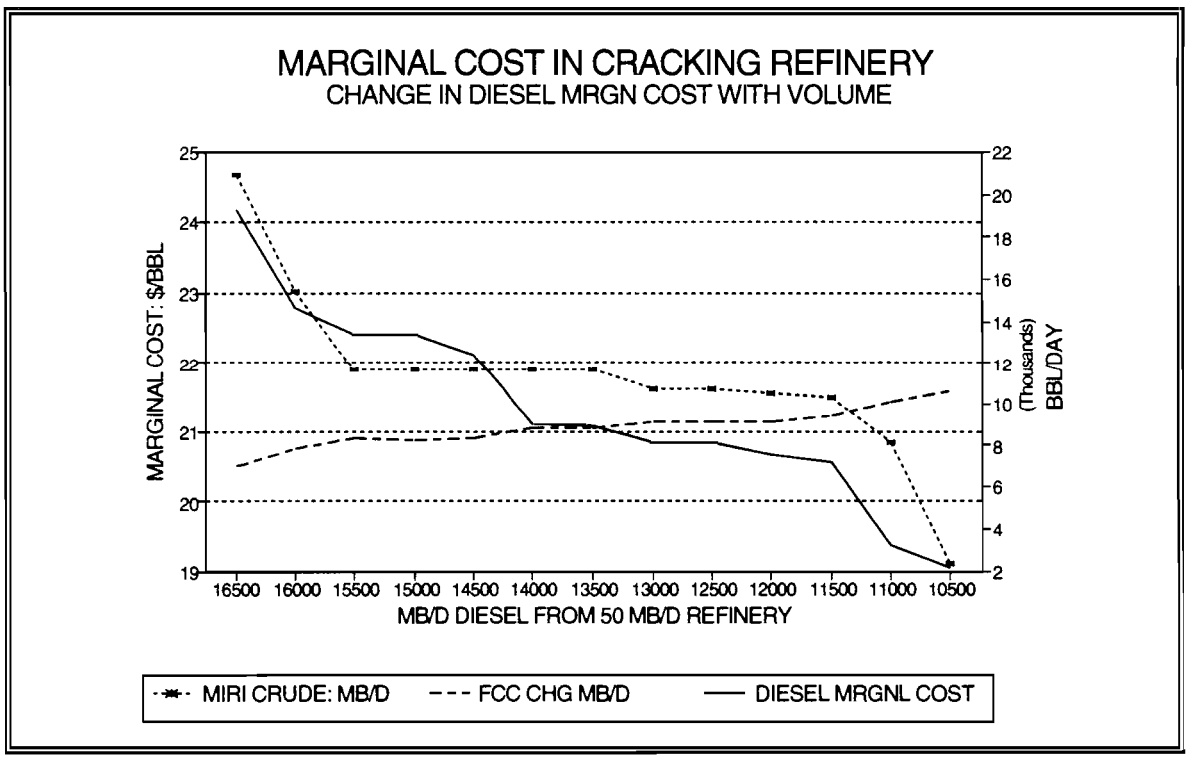
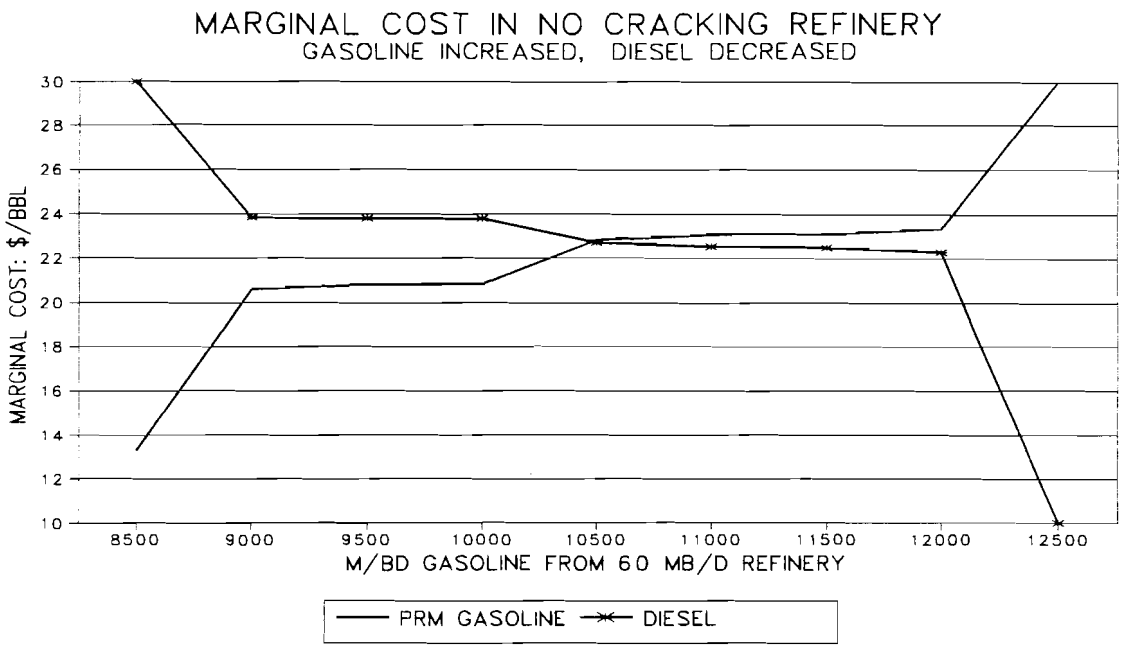

MARGINAL COST IN CRACKING REFINERY
CHANGE IN DIESEL MRGN COST WITH VOLUME
MARGINAL COST: $/BBL
25
24
23
22
21
20
19
22
20
18
16
14
12
10
8
6
4
2
(Thousands)
BBL/DAY
16500 16000 15500 15000 14500 14000 13500 13000 12500 12000 11500 11000 10500
MB/D DIESEL FROM 50 MB/D REFINERY
MIRI CRUDE: MB/D
FCC CHG MB/D
DIESEL MRGNL COST

Figure 4-5



4.2 Refining Production Cost and Market Prices - Responsive Interaction

The market interaction between the supplier and the buyer of oil products will first be described in terms of no price controls. Then, the difficulties that exist when price controls are placed on oil products will be described with emphasis on problems that have occurred within the Philippine oil price control experience. The examples that will be used to describe market interaction with and without price controls will focus on gasoline and diesel fuel. The principles described for these fuels apply to the whole array of oil products. Gasoline and diesel have been chosen to illustrate the principles and problems because:

- There are major, high quality products.
- The demands are interrelated, as both compete in transportation markets.
- Supply/demand/pricing problems for these products exist in the Philippines.
- The two fuels are related in energy policy issues of conservation, environment, taxation, and social policy.

As shown in Figure 4-5, the costs to produce gasoline and diesel depend on the relative volumes produced, which depend on relative volumes demanded. Market price and the cost of the incremental or marginal barrel are not always equal but market forces push towards that equalization. In all markets, prices are usually discussed at two levels: i)the refinery gate (or terminal) and ii)the consumer prices. If marketing and distribution costs are temporarily ignored to simplify the illustration, then the gate price plus a tax (which as far as the consumer is concerned is just another cost component of the price) is the price the buyer pays for the product. In fact, to illustrate market interaction, assume that a decision has been made to increase the tax on gasoline while keeping diesel tax unchanged.

In the short term, in response to the increase in price, gasoline demand will fall as consumers with gasoline-powered vehicles reduce the number of miles they drive. Diesel demand would change very little, although diesel-powered public transportation vehicles may see increased ridership as people make less use of personal cars. The refinery must now produce less gasoline, while diesel volume remains the same; diesel's relative percentage of total product grows. Based on the results previously shown, the incremental cost of gasoline would fall and diesel would rise; that is, the buyer should expect to pay more at the refinery gate for diesel. At the consumer level, the increase in gasoline price should be less than the increase in gasoline tax. Consider a second example in which several new diesel-powered combined-cycle electrical generating facilities come on-stream in the span of a few months, adding a sudden increase in diesel demand of five percent. To the refiner producing 5% more diesel, this may mean an increase in the incremental cost of production of .05 US$/bbl or up to 3.00 US$/bbl, depending on the volume fraction of diesel that was being produced prior to the increased demand. If production is already at relatively high distillate production levels, then it may be more economical for the refiner to import distillate rather than produce it, even though delivery cost may add over 1.00 US$/bbl to the FOB purchase cost.

It is important to remember that the changes in volume demand mean real changes in production cost, such as having to use more high-priced premium crude and/or having to reduce the use of the FCC unit and losing part of its product upgrading benefits. The changes in incremental product costs are a consequence of real cost changes in feedstock and operating costs, and an appropriate price change process provides the incentives for the refiner to change the volume mix of product to meet the new demand. Moreover, the process will encourage the refinery to achieve the most efficient use of feedstock and production facilities.

4.3 Oil Product Price Controls - Impacts On Market Interactions

The previous sections have already revealed some of the potential difficulties that can be faced in trying to effectively control the refinery gate price of products. Effectively controlling prices for a multi-product process such as oil refining is far more difficult than controlling the price of a single product process such as electricity generation. The problems that can occur when attempting to control oil product prices and their past and potential impacts on the Philippine refinery industry are described in this section.

In a market-driven system without price controls, prices and incremental production costs adjust to equilibrium and the volumes supplied meet the volumes demanded. Marginal costs and prices are seldom equal, but the market price signals move supply and demand toward equilibrium. With price controls, if an oil product price is significantly below incremental production cost, refiners are not economically motivated to produce sufficient product to meet demand. When the controlled price is too high, the impact is less obvious; although the refiner would be willing to supply more product at that price, he simply supplies what is needed. The consumer is paying an artificially higher price and may, as a consequence, buy more of a substitute product. The result of overpricing is inefficient use of resources at the expense of the consumer.

The price control approach for setting refinery gate prices in the Philippines is based on the assumption that the relative product prices on the Singapore cargo market are appropriate for application to the Philippine oil product market. However, while Singapore may be the best market outside the Philippines to use as a source for oil product price data, there are

differences which indicate that the Singapore prices may not adequately represent an efficient Philippine oil market. The consequence is some price distortion and market inefficiency.

The Singapore market has some very important similarities to the Philippine oil product market. Crude price differences are one of the most important determinants of relative product prices and the arrival costs for the various types of crudes into Singapore are very close to the arrival costs into the Philippines. The product mix is similar in the Philippines and Singapore, both with strong middle distillate markets, but as shown in the incremental cost analysis, changes of a few volume percent can have dramatic impacts on incremental production costs. Differences in the two markets include greater refining complexity in Singapore and a strong orientation to export markets.

When the Singapore prices are used for price control in the Philippines, the prices into the Philippine market are calculated by adding shipping costs and duty cost. Adding a 20 or 30% duty has the impact of spreading the product differential. However, the costs of the different types of crude are also spread by a duty cost, and the overall price control calculation ultimately leaves the price differentials relatively intact.

Based on the analysis of this study, the most prominent pricing problem is the controlled price of diesel fuel oil. The Singapore parity price calculation would have worked fairly well for a number of years, but in the past few years a problem has arisen; diesel demand in the Philippines has changed dramatically. As shown in Table 4-3, diesel demand was only 18.5% of oil product volumes in 1975; by 1985 it was 28.8%, and by 1990 it had grown to 32.1%. In 1991, Philippine diesel demand was 32.1% and DOE's projection is 33.7% for 1992, with diesel consumption growth continuing for the next five years at a rate exceeding total oil product growth. At the current Philippine diesel demand level, if all diesel were produced by domestic refiners, the incremental production cost of diesel would be higher than that of premium gasoline (up to 2 to 3 US$/bbl based on the runs of Table 4-2). When diesel demand volumes reach the projected high levels:

- Domestic refiners cannot cost-effectively produce incremental volumes.
- It is more efficient to import incremental volumes.
- Price should be adequate to attract diesel imports.

One important issue is whether the import parity price provides an adequate price for a product import. If premium gasoline is selling for 1 US$/bbl more than diesel in Singapore, then the import parity calculation maintains approximately that price differential into the Philippine market. If it costs 1.50 US$/bbl to deliver diesel from Singapore to the Philippines, then diesel should, in fact, be priced at .50 US$/bbl over premium gasoline in the Philippines (assuming no duty). The most economic source of incremental gasoline is domestic refinery production and the price should be in line with the cost for those respective sources.

As discussed in Chapter 8, duties on crude and oil products can create some problems, particularly when product duties are significantly higher than crude duties. If the import price has to reflect both delivery cost and duty differential, then it will encourage a degree of inefficiency in domestic refining.

The analysis of pricing and incremental costs in this section has been focused on the premium, high-quality, light products: gasoline and diesel. In the last 20 years, a significant change in relative oil product pricing is the increase in price differential between the light

Table 4-3

Petroleum Product Consumption
(Thousand Barrels)

	1975	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
Avgas	185	62	59	59	51	39	36	35	36	39	39	36	28
Avturbo	2165	2605	2588	3436	2658	2824	2712	2716	3304	3758	4261	3983	3892
Premium Gasoline	5124	5866	5700	5941	6206	5954	5885	6334	7055	7751	8829	9390	8112
Regular gasoline	10132	5299	3942	3270	2971	2717	2562	2806	3090	3248	3471	3465	2965
Kerosene	3154	3179	2860	2803	2569	2269	2074	2273	2545	2815	3456	3704	3579
Diesel	13227	17428	17787	18568	18879	17090	15702	16223	17839	19186	22237	25220	26534
Fuel Oil	29829	37129	34385	32971	33690	24390	20039	21511	26645	28002	30349	30375	28570
LPG	2086	2411	2437	2524	2533	2225	2234	2464	2843	3503	4183	4598	4742
Asphalts	425	343	359	462	538	347	284	295	282	317	342	286	326
Solvents	244	311	312	297	270	155	160	200	246	288	297	267	182
Lubes and Greases	942	993	927	939	1067	796	710	747	897	887	1058	1070	907
Others	331	237	213	107	186	147	0	5	8	10	15	14	11
Refinery Fuel & Loss	3533	3283	2847	2993	2853	2479	2098	2139	2354	2856	3052	3071	2907
Total Petroleum Consumption	71377	79141	74416	74370	74472	61432	54539	57742	67144	72660	81609	85479	82757
Volume Percent													
Avgas	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0
Avturbo	3.0	3.3	3.5	4.6	3.6	4.6	5.0	4.7	4.9	5.2	5.2	4.7	4.7
Premium Gasoline	7.2	7.4	7.7	8.0	8.3	9.7	10.8	11.0	10.5	10.7	10.8	11.0	9.8
Regular gasoline	14.2	6.7	5.3	4.4	4.0	4.4	4.7	4.9	4.6	4.5	4.3	4.1	3.6
Kerosene	4.4	4.0	3.8	3.8	3.4	3.7	3.8	3.9	3.8	3.9	4.2	4.3	4.3
Diesel	18.5	22.0	23.9	25.0	25.4	27.8	28.8	28.1	26.6	26.4	27.2	29.5	32.1
Fuel Oil	41.8	46.9	46.2	44.3	45.2	39.7	36.7	37.3	39.7	38.5	37.2	35.5	34.5
LPG	2.9	3.0	3.3	3.4	3.4	3.6	4.1	4.3	4.2	4.8	5.1	5.4	5.7
Asphalts	0.6	0.4	0.5	0.6	0.7	0.6	0.5	0.5	0.4	0.4	0.4	0.3	0.4
Solvents	0.3	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.4	0.4	0.4	0.3	0.2
Lubes and Greases	1.3	1.3	1.2	1.3	1.4	1.3	1.3	1.3	1.3	1.2	1.3	1.3	1.1
Others	0.5	0.3	0.3	0.1	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refinery Fuel & Loss	4.9	4.1	3.8	4.0	3.8	4.0	3.8	3.7	3.5	3.9	3.7	3.6	3.5
	100.0	100.0	100.0	100.0	100.0	100.0	99.9	100.0	100.0	100.0	100.0	100.0	100.0

57

refined products and the heavy fuel oil product. The fundamental refining factors that determine the cost to produce the light vs heavy products and their influence on pricing for the Philippine market are described in this section.

Heavy fuel oil, also sometimes referred to as residual fuel oil (or simply "resid"), is made from the heavy, high boiling fractions of crude oils. Heavy fuel oils are principally used as boiler fuels in industrial applications and for power generation. Competing in the boiler markets coal and gas, the heavy fuel oils have lost market share as crude prices have risen. This loss of market share has reduced the volume fractions of heavy fuel oil to be produced by most refiners around the world.

Refiners can reduce the production of heavy fuel by two means. The first is to purchase crude oils that contain less of the high boiling heavy material. The second is for the refiner to convert or "upgrade" some of the heavy material to lighter, higher-valued products. Converting heavy material requires both added refinery operating expenses and equipment. Changing the types of crude purchased or using conversion facilities will change the incremental cost of the oil products produced by refiners.

The less heavy material a crude contains, the more valuable it is. Shown below are the four crudes used in the incremental cost analysis:

	Arab Heavy	Arab Light	Murban	Miri Light
Gravity, °API	28.2	34.4	39.2	36.3
Sulfur, Wt%	2.80	1.69	0.81	0.08
Heavy Boiling Fractions (Vol% of Crude):				
Heavy Gas Oil (350-578°C)	21.1	24.5	23.6	17.2
Bottoms (578°C+)	29.6	16.2	9.5	3.7
Crude Price, US$/bbl	15.40	18.00	19.05	21.00

The bottoms fractions are the most difficult to convert and the highest priced crude, Miri, has only 3.7% bottoms as compared with Arab Heavy, which has 29.6% bottoms. The heavy crudes also tend to have higher sulfur contents which also lessens their value, since environmental limits on sulfur content of products may require partial sulfur removal, which means added processing costs.

The relationship between the price differential of light and heavy crudes and the refiner's incremental cost to produce light and heavy products is shown in the series of refinery model runs of Table 4-4. The differential between light and heavy crude prices has been increasing; Table 4-4 shows three sets of crude prices with high, medium, and low light-heavy differentials that have occurred in the past several years. In the high differential columns, the price difference between Miri and Saudi Heavy is greatest (6.65 US$/bbl), and the differential between the incremental cost to produce premium gasoline and heavy fuel oil is 10.09 US$/bbl. When the crude price differential is the smallest (4.20 US$/bbl) the incremental product cost differential is 6.12 US$/bbl.

Table 4-4

IMPACT OF CHANGE IN LIGHT - HEAVY CRUDE PRICE DIFFERENTIAL ON COST OF PRODUCING PRODUCTS

Caltex Batangas Refinery	Light - Heavy Crude Price Differential: High		Medium		Low	
Crude Inputs	VOLUME MB/CD	PRICE $/B	VOLUME MB/CD	PRICE $/B	VOLUME MB/CD	PRICE $/B
Arab Hy (28.2API 2.80S)	8.621	15.10	8.655	15.40	8.909	16.40
Arab Lt (34.4API 1.69S)	16.000	18.00	16.000	18.00	16.000	18.00
Miri Lt (36.3API 0.08S)	10.412	21.75	10.643	21.00	12.284	20.60
Murban (39.2API 0.81S)	11.614	19.38	11.332	19.05	9.332	18.90
Total Crude	46.647	18.64	46.630	18.46	46.525	18.56
Refinery Outputs						
Products	VOLUME MB/CD	INC-VAL $/B	VOLUME MB/CD	INC-VAL $/B	VOLUME MB/CD	INC-VAL $/B
Premium Gasoline	9.750	22.49	9.750	21.75	9.750	21.54
Regular Gasoline	3.250	20.71	3.250	19.97	3.250	19.76
Diesel Fuel	10.215	21.58	10.215	20.83	10.215	20.59
Diesel Fuel-Lo Sulf	2.785	21.58	2.785	20.83	2.785	20.59
Heavy Fuel Oil	9.000	12.40	9.000	13.71	9.000	15.42
Hvy Fuel Oil-Lo Sulf	0.500	18.54	0.500	19.08	0.500	18.30
Other	10.491		10.475		10.355	
Total Product	45.991		45.975		45.855	
Process Unit	CHARGE MB/CD	CAPACITY MB/CD	CHARGE MB/CD	CAPACITY MB/CD	CHARGE MB/CD	CAPACITY MB/CD
Atmospheric Distillation	46.647	71.000	46.630	71.000	46.525	71.000
Catalytic Reforming	4.949	7.000	4.957	7.000	5.112	7.000
Low Severity	4.949		4.957		5.112	
High Severity	0.000		0.000		0.000	
Catalytic Cracking	9.099	12.500	9.075	12.500	8.834	12.500
Low Conversion	3.299		3.249		3.523	
High Conversion	5.801		5.826		5.331	
MIRI - SAUDI HVY PRICE DELTA		6.65		5.6		4.2
PRM GASO - Hvy FO PRICE DELTA		10.09		8.04		6.12

A second series of runs shown in Table 4-5 shows the changes in the differentials between incremental light and heavy production costs as the volume percentage of heavy fuel oil production is decreased. As shown, as the volume percentage of heavy fuel oil product decreases, the incremental cost of heavy oil decreases and the incremental cost of lightproducts increases, representative of typical world refinery experience. When the demand for heavy fuel falls, the relative price of heavy fuel falls because surplus volumes are available. The widening price differential between light and heavy products thus provides an incentive to refiners to add processing equipment in an effort to reduce heavy oil production and improve refinery economics.

The incremental light-heavy production cost differentials from Table 4-4 where light-heavy crude prices were changing are compared below with those with the Singapore spot product market differentials:

	Price Differentials: US$/bbl		
	High	Medium	Low
Miri-Saudi Heavy Crude Price Differential	6.65	5.60	4.20
Incremental Production Cost Differential (Premium Gasoline - Heavy Fuel)	10.09	8.04	6.12
Singapore Spot Market (Premium Gasoline - Heavy Fuel)	15.50	13.50	11.30

As shown, the Singapore light-heavy product spot price differentials change with changes in crude price differentials, but they are in each case about 5 US$/bbl greater than the Philippine refinery incremental production cost differential. This is not surprising; the Singapore refineries are more complex and operating at a higher bottom conversion rate which is in keeping with a higher light-heavy product price differential. This comparison suggests that satisfying some of the Philippines heavy fuel oil needs by imports from Singapore could be economically beneficial to both countries.

4.4 Summary and Recommendations

A Linear Program (LP) model was developed and documented for each of the three Philippine refineries. Training sessions and manuals were furnished to DOE for its use in further analysis of production cost in the Philippine refining industry.

The cost of production of a refined product changes as the production level of that product changes. The cost at any level of production is interdependent, among other variables, on crude selection availability, crude cost, crude assays, product specifications, yield correlations, variable cost of refinery units, unit capacities, ability to vary operations, and production levels of other products being co-produced.

Analyses demonstrate that the marginal cost of producing a given product at a low level of production is much less costly than when production of that product is pushed to near maximum levels. As an example, the marginal cost of diesel production in a 50,000 B/D FCC refinery was shown to be about $19 per barrel at a production level of 10,500 B/D but

Table 4-5

IMPACT OF CHANGE IN HEAVY FUEL OIL PRODUCT REQUIREMENT ON COST OF PRODUCING PRODUCTS

HEAVY FUEL OIL PRODUCTION LEVEL

Caltex Batangas Refinery	Low		Medium		High	
Crude Inputs	VOLUME MB/CD	PRICE $/B	VOLUME MB/CD	PRICE $/B	VOLUME MB/CD	PRICE $/B
Arab Hy (28.2API 2.80S)	3.121	15.40	8.655	15.40	13.894	15.40
Arab Lt (34.4API 1.69S)	16.000	18.00	16.000	18.00	16.000	18.00
Miri Lt (36.3API 0.08S)	16.073	21.00	10.643	21.00	8.960	21.00
Murban (39.2API 0.81S)	7.833	19.05	11.332	19.05	11.223	19.05
Total Crude	43.027	19.12	46.630	18.46	50.198	18.05

Refinery Outputs

Products	VOLUME MB/CD	INC-VAL $/B	VOLUME MB/CD	INC-VAL $/B	VOLUME MB/CD	INC-VAL $/B
Premium Gasoline	9.750	22.24	9.750	21.75	9.750	20.90
Regular Gasoline	3.250	20.46	3.250	19.97	3.250	19.06
Diesel Fuel	10.215	21.21	10.215	20.83	10.215	19.97
Diesel Fuel-Lo Sulf	2.785	21.21	2.785	20.83	2.785	20.03
Heavy Fuel Oil	6.000	12.71	9.000	13.71	12.000	16.64
Hvy Fuel Oil-Lo Sulf	0.367	12.71	0.500	19.08	0.633	21.30
Other	10.000		10.475		11.444	
Total Product	42.367		45.975		50.077	

Process Unit	CHARGE MB/CD	CAPACITY MB/CD	CHARGE MB/CD	CAPACITY MB/CD	CHARGE MB/CD	CAPACITY MB/CD
Atmospheric Distillation	43.027	71.000	46.630	71.000	50.077	71.000
Catalytic Reforming	6.187	7.000	4.957	7.000	4.972	7.000
Low Severity	6.187		4.957		4.972	
High Severity	0.000		0.000		0.000	
Catalytic Cracking	8.155	12.500	9.075	12.500	9.962	12.500
Low Conversion	3.036		3.249		9.962	
High Conversion	5.119		5.826		0.000	

MIRI - SAUDI HVY PRICE DELTA	5.6	5.6	5.6
PRM GASO - Hvy FO PRICE DELTA	9.53	8.04	4.26

increased to over $24 per barrel when production was forced to 16,500 B/D. Similarly, the marginal cost of premium gasoline was about $17 when total gasoline production was set at 9,500 B/D but increased to over $24 at a gasoline production level of 15,500 B/D.

Diesel prices in the Philippines have been set low relative to gasoline resulting in a distorted increased diesel demand. The Philippine refiners are at economic maximum diesel production levels. The distorted price has been a major factor in the reason that diesel has increased from 18.5% of product demand in 1975 to an estimated 33.7% in 1992.

Singapore-based control prices used in the Philippines have been analyzed to determine if they are the most appropriate to insure that production processes are as efficient as possible and that buyer needs are supplied at the best prices. Results indicate that all gasoline product can best be produced domestically, but some imported diesel and some heavy fuel oil may bring domestic refineries into better balance and make production more economical. This would mean that diesel and heavy oil prices in the Philippines would both be higher relative to gasoline by the amount of the delivery transportation costs.

5 REFINING FACILITIES AND EFFICIENCY

Refining efficiency needs to be analyzed from two viewpoints: i)effective control of operating costs and ii)effective utilization of process facilities. The first viewpoint addresses how effectively refiners are controlling operating costs: fuel, staffing, utilities, catalyst, etc. The operating costs of the Philippine refineries were examined and reported previously in "Cost Structure and Transfer Pricing for the Philippine Petroleum Industry: Technical Report". The second aspect of refinery efficiency deals with how refiners can most effectively utilize process facilities and minimize feedstock and operating costs to produce refined products to meet consumer needs. This second aspect of efficiency is analyzed in this chapter. Specifically, the following questions are addressed:

- Given crude and product prices, what mix of products can be produced most economically by the Philippine refineries?
- How does that best mix of products change with a change in the relative prices of products, and how does the mix change when product demand constraints are introduced?
- How do product price controls affect efficiency?
- What changes in Philippine refining facilities will be called for based on Philippine energy policy and changes in future product demands?

The first question is analyzed from the standpoint of refiners in terms of how each can utilize facilities and crude feedstock choices to make the best mix of refined products for the market. Every refiner making his best mix of products would both maximize profit margin and provide products to the consumer at the least cost. However, with each refiner producing his best mix of products, the collective production volumes of individual products may not be in keeping with total consumer demand when controlled prices do not adequately reflect demand pull for products. This is the essence of the problem of economic distortion in a price control environment.

5.1 LP Model Solution Analysis

Table 5-1 shows the refinery LP model solution for the run analyzing the best product mix for the Caltex refinery. Given the prices, the "refinery" selects the optimum production levels for gasoline (premium, regular and reformate) at 28.2%, middle distillates (kerosene, jet and diesel) at 46.4%, heavy fuel oil at 17.2%, and other (8.2%).

In the Caltex refinery simulation run (Table 5-1) differentials for product prices are based on the Singapore spot market for the past several years. The refinery can select from the four crude types that were described in Chapter 4. A minimum requirement of 19,200 bbl/d of Arabian Light crude was imposed; if the model were allowed a free choice of crude oils, some of the Arabian Light would be replaced with a combination of Miri and Arabian Heavy, and middle distillate production would be increased slightly. In the run shown in by Table 5-1, the model chose to operate both the reformer and the FCC unit at full capacity. The FCC unit was also operated at the higher severity, maximizing gasoline production.

Refinery simulation runs were made to determine the impact of changing heavy fuel oil production requirements and relative product prices on the mix of refinery products made. The base run for the series of runs is the Caltex refinery run just described (C1) and the product mixes of the four runs are compared in Table 5-2.

Table 5-1

ANALYSIS OF OPTIMAL PRODUCT MIX

Caltex Batangas Refinery — Run: C1

Refinery Crude Inputs	PRICE $/B	VOLUME MB/CD	MIN MB/CD	MAX MB/CD	INC-VAL $/B
Arab Hy (28.2API 2.80S)	16.40	2.258	0.000	No Lim	16.40
Arab Lt (34.4API 1.69S)	19.00	19.200	19.200	No Lim	18.02
Miri Lt (36.3API 0.08S)	22.00	1.846	0.000	No Lim	22.00
Murban (39.2API 0.81S)	20.05	47.697	0.000	No Lim	20.05
Total Crude		71.000			

Refinery Outputs Products	PRICE $/B	VOLUME MB/CD	MIN MB/CD	MAX MB/CD	INC-VAL $/B
Liquid Petroleum Gas	28.65	3.282	0.720	4.000	28.65
Premium Gasoline	29.50	13.504	10.200	20.000	29.50
Regular Gasoline	26.90	4.841	3.420	5.000	26.90
Naphtha Product	24.00	2.400	2.400	3.600	22.45
Reformate Product	31.50	1.440	0.600	1.440	33.41
Kerosene-Jet Fuel	29.00	7.200	5.760	7.200	29.95
Kero. Solvents	29.00	0.240	0.120	0.240	29.95
Naph. Solvents	24.00	0.120	0.120	0.240	22.45
Diesel Fuel	27.70	22.251	10.000	30.000	27.70
Diesel Fuel-Lo Sulf	27.70	2.880	2.880	6.900	27.60
No 6 Fuel Oil	15.31	11.291	9.600	18.000	15.31
No 6 Fuel Oil-Lo Sulf	18.31	0.540	0.540	0.660	15.86
Asphalt - Pitch	17.92	0.240	0.120	0.240	26.96
Total Product		70.229			
Fuel Burned (FOEB)		2.272			
Total Output		72.502			

Process Unit Summary Process Unit	CHARGE MB/CD	CAPACITY MIN MB/CD	CAPACITY MAX MB/CD	INC-VAL $/B
Atmospheric Distillation	71.000	0.000	71.000	-4.22
Vacuum Distillation	19.500	0.000	19.500	-3.64
Catalytic Reforming	7.000	0.000	7.000	-2.45
Low Severity	5.499			
High Severity	1.501			
Catalytic Cracking	12.500	0.000	12.500	-2.19
Low Conversion	0.000			
High Conversion	12.500			
LPG Treater	3.282	0.000	4.100	
Naphtha Hydrotreater	9.266	0.000	12.500	
Kero-Jet Merox Treater	7.477	0.000	11.000	
Distillate Hydrotreater	0.888	0.000	16.000	

Table 5-2

CALTEX REFINERY SIMULATION RUNS

Run No.	C1	C2	C3	C4
Crude Oil Volumes (bbl/d)				
Arab Heavy	2,259	9,822	---	9,822
Arab Light	19,200*	19,200*	19,200*	10,200
Murban	47,697	39,928	40,174	39,928
Miri Light	1,846	2,051	11,626	2,051
Product Prices (US$/bbl)				
Premium Gasoline	29.50	29.50	29.75	29.75
Diesel Fuel	27.70	27.70	29.75	29.75
Heavy Fuel Oil	15.31	15.31	13.03	13.03
Product Volumes (Vol%)				
Gasolines	29.2	27.3	28.1	27.3
Middle Distillates	46.4	42.6	49.1	42.5
Heavy Fuel Oil	17.2	21.7*	14.6	21.7*
Other	8.2	8.4	8.2	8.5

* Minimum required feedstock or production level.

In run C2, a heavy fuel oil production requirement of 21.7% was imposed and, comparing with run C1, feedstock was shifted to run more heavy crude. The increase in fuel oil production was primarily achieved by reducing production of middle distillates. For runs C3 and C4, the price differential between gasoline and middle distillate was reduced to zero. Comparing C3 and C1 shows increased middle distillate production and decreased heavy fuel production in response to the increased price of distillate and higher light-heavy product price differential. The same minimum heavy fuel oil production was required in C4 as in C2. Comparing runs C3 and C4, the increase of heavy fuel oil production from 14.6% to 21.7% (7.1% change) was accompanied by a decline in middle distillates production from 49.1% to 42.5% (6.6% change).

In all of these runs, the FCC unit was operated at maximum capacity and high conversion level and the reformer was operated at full capacity and in the lower severity range. The combination of FCC and reformer operation provides maximum gasoline production while meeting product specifications. In actual practice, it would be possible to further increase gasoline production if a higher conversion cracking catalyst were employed in the FCC unit. As previously noted, distillate production could be increased slightly by removing the minimum limit on use of Arabian Light crude, which would permit greater use of the Miri crude which has a larger distillate fraction.

A set of runs was also made to simulate the Shell refinery's utilization of feedstock and process units. The base run is shown in Table 5-3. The major difference between the Shell and Caltex refineries is that the Caltex refinery has an FCC unit. The volume percentage yields for the base Shell and Caltex refinery runs are compared in Table 5-4. Caltex's FCC unit converts material boiling in the heavy fuel oil range to light products as indicated by the higher light product yields (gasoline and middle distillates) as shown in Table 5-4.

Table 5-4

Run No.	Caltex Refinery C1	Shell Refinery C2
Gasolines (Vol%)	28.2	19.6
Middle Distillates (Vol%)	46.4	38.2
Heavy Fuel Oil (Vol%)	17.2	37.2
Other (Vol%)	8.2	5.0

The series of simulation runs for the Shell Refinery are presented in Table 5-5.

Table 5-5
SHELL REFINERY SIMULATION RUNS

Run No.	S1	S2	S3	S4
Crude Oil Volumes (bbl/d)				
Arab Heavy	23,283	28,594	13,517	18,765
Arab Light	18,000*	---	18,000*	18,000
Murban	28,610	41,299	8,713	18,164
Miri Light	2,907	2,907	32,570	17,871
Product Prices (US$/bbl)				
Premium Gasoline	29.50	29.50	29.75	29.75
Diesel Fuel	27.70	27.70	29.75	29.75
Heavy Fuel Oil	15.31	15.31	13.03	13.03
Product Volumes (Vol%)				
Gasolines	19.6	19.6	20.0	19.8
Middle Distillates	38.2	38.8	47.6	42.9
Heavy Fuel Oil	37.2	36.6	29.2	33.2*
Other	5.0	5.0	3.2	4.1

* Minimum required feedstock or production level.

Table 5-3

ANALYSIS OF OPTIMAL PRODUCT MIX

Shell Tabangao Refinery — Run: S1

Refinery Crude Inputs	PRICE $/B	VOLUME MB/CD	MIN MB/CD	MAX MB/CD	INC-VAL $/B
Arab Hy (28.2API 2.80S)	16.40	23.283	0.000	No Lim	16.4
Arab Lt (34.4API 1.69S)	19.00	18.000	18.000	No Lim	18.69
Miri Lt (36.3API 0.08S)	22.00	2.907	0.000	No Lim	22
Murban (39.2API 0.81S)	20.05	28.610	0.000	No Lim	20.05
Total Crude		72.800			

Refinery Outputs Products	PRICE $/B	VOLUME MB/CD	MIN MB/CD	MAX MB/CD	INC-VAL $/B
Liquid Petroleum Gas	28.65	3.032	1.000	5.000	28.65
Premium Gasoline	26.90	4.721	4.000	8.000	26.90
Regular Gasoline	29.50	7.000	7.000	14.000	29.00
Naphtha Product	24.00	0.000	0.000	5.000	23.02
Reformate Product	31.50	2.302	1.000	5.000	31.50
Kerosene-Jet Fuel	29.00	6.167	5.500	8.000	29.00
Kero. Solvents	29.00	0.500	0.500	1.000	29.00
Naph. Solvents	24.00	0.500	0.500	1.000	20.10
Diesel Fuel	27.70	19.000	19.000	25.000	27.70
Diesel Fuel-Lo Sulf	27.70	1.649	1.000	5.000	27.70
No 6 Fuel Oil	15.31	25.584	14.000	30.000	15.31
No 6 Fuel Oil-Lo Sulf	18.31	1.000	1.000	5.000	18.19
Total Product		71.455			
Fuel Burned (FOEB)		1.829			
Total Output		73.284			

Process Unit Summary Process Unit	CHARGE MB/CD	CAPACITY MIN MB/CD	CAPACITY MAX MB/CD	INC-VAL $/B
Atmospheric Distillation	72.800	0.000	72.800	-4.01
Catalytic Reforming	10.300	0.000	10.300	-1.53
Low Severity	2.677			
High Severity	7.623			
LPG Treater	3.032	0.000	3.500	
Naphtha Hydrotreater	10.848	0.000	19.800	
Kero-Jet Merox Treater	6.700	0.000	6.700	-1.13
Distillate Hydrotreater	0.000	0.000	5.800	

As shown in the table, in run S2 the minimum requirement for use of Arabian Light crude was dropped, and a more economically attractive combination of Murban and Saudi Heavy was substituted. On the product side, there was a slight gain in middle distillate production, and a corresponding reduction in heavy fuel oil production. In runs S3 and S4, the diesel price was increased to parity with premium gasoline. Run S3 has the same minimum heavy fuel production requirement as S1; the increase in diesel price resulted in a significant increase in distillate production and an associated decline in heavy fuel production. The change in yield was primarily accomplished by an increase in the use of Miri crude. In run S4, production of more heavy fuel was required, and both Miri crude use and distillate production fell as compared to S3.

How does this analysis of optimal operations for Caltex and Shell compare to actual refinery operation? Before comparing model results from this study with actual production, it is important to remember that the model developed for this study was designed to be flexible and examine a wide range of variation in crude usage and operational variation, and to generate cost changes over that range. The models are "blocked crude" models using crude assay data and unit process correlations. Results may not show exact agreement with refinery yield figures, but should give a good approximation of the relative impacts of operational change. The refining production data for Caltex and Shell are summarized in Table 5-6.

Table 5-6

	Shell		Caltex	
Product Yields, Vol%	**1990**	**1991**	**1990**	**1991**
Gasolines	15.5	17.3	25.7	22.8
Middle Distillates	45.7	46.2	50.7	52.1
Heavy Fuel Oil	32.7	32.4	19.4	17.9
Other	6.1	4.1	4.2	7.2

The differences between the study runs and the actual refinery yields are similar for both Shell and Caltex. Actual middle distillates production for both are closest to the price parity cases C3 and S3. Actual gasoline production is lower than the model optimal study cases (C1 and S1). These comparisons are not surprising, refiners respond to two things: prices and customer needs. More distillate and less gasoline are made because of customer demand, however, the study analysis results are still relevant. Given the relative prices of gasoline and middle distillates and the refining facilities and costs, both Shell and Caltex should find new gasoline sales volumes to be more economically attractive than additional diesel sales volumes. For example, a new power generation facility in the Philippines which was seeking diesel fuel for running gas turbines might not find these refiners very interested in supplying new diesel fuel volumes. Producing more diesel would mean co-producing more gasoline, and that gasoline cannot be sold at the controlled price but would have to be sold on the export market. In the export market, it would have to bear the burden of crude duty in its feedstock cost, and a transportation cost to the sales destination.

5.2 Oil Product Pricing and Refinery Facility Investment Decisions

The Philippine government plays an enormous role in determining the climate for and success of refinery investments. Energy policy affects refineries by setting prices at the refinery gate and also by setting taxes and duties which are large factors in determining consumer prices and demand. Oil pricing and refining investment decision making are discussed by focusing on the following items:

- Tax and duty decisions → price consequences → relative demand for oil products.
- Control price setting → relative gate prices → return on upgrading facilities.
- Product quality requirements → refining cost increases → gate price changes required.

Refinery facility needs and decision-making are affected by oil product prices at both the consumer level and at the refinery gate. Prices at the consumer level include tax and duties in addition to the refiner's costs and profit on the products. When tax and duty amounts vary across the product barrel, the relative product demand is affected. In the past, the tax and duty component (including OPSF) for diesel fuel has been significantly less than that for gasoline, and diesel demand has grown at a faster rate than gasoline demand. In the past, this tax policy achieved a desired benefit: a lower priced transportation fuel has been available to the public transport sector. Also, up to a point, using both gasoline and diesel as transport fuels helps to "get the most miles out of the crude barrel."[1]

A diesel engine gets about 25% more kilometers per liter than gasoline, due in part to the higher energy density and in part to the engine efficiency. But at the current high levels of diesel demand in the Philippines, it may be appropriate to consider energy policies that foster lower diesel demand growth. While generally the cost to produce more gasoline exceeds the cost to produce any other refined product, the point has been reached in the Philippines where that is not true in the case of diesel production costs. At this point, less rapid growth in diesel demand would mean a better utilization of refinery facilities.

Crude and product price differentials, rather than refinery margins, are the primary determinants of the success or failure of refinery upgrading investment decisions. Of course, changing price differentials can also be accompanied by change in margin level, as these are not independent variables. Upgrading can mean a refiner is able to make the same mix of products from a poorer quality crude, or an improved mix of products from the same crude, or somewhere between those extremes. A refiner gearing to use a poorer crude may be betting on crude differentials as a basis for return. But the situation in the Philippines is more a matter of improving product mix, and that means adding equipment to make more higher priced products and less lower priced products. In this case, the refiner is betting on how the price differences will be controlled. That means relative prices, especially in the case of diesel vs gasoline, need to reflect market forces.

---

[1] "Diesel: Miles Per Barrel", Wagner, T.O., Lawerence, D.K., and Plautz, "HYDROCARBON PROCESSING", Jan. 1981.

Investors are often reluctant to believe that controlled prices in the future will adequately reflect the market forces that are the basis for the investment need. Price controls can disrupt and distort the clear reading of the market trends the refining facility investor needs to see. Even if the price controllers are sensitive to giving buyers and producers correct price signals for matching supply to demand needs, the existence of controls obstructs a clear understanding of what those prices should be. As noted earlier, Philippine diesel prices should be higher relative to gasoline prices than in Singapore. Also, the Philippine light-heavy product price differential should be a bit less than in the Singapore market. Exactly how much these price differentials should be could best be determined in a decontrolled environment, where domestic products and import product volumes interact to achieve the most efficient supply balance and provide the best prices for consumers.

Does the Philippine price control mechanism's impact on crude oil pricing affect the refinery facility decision-maker? The control pricing mechanism does not alter the relative acquisition prices of crudes, but it does allow increased crude cost to automatically be translated into higher product prices. But regardless of how product prices are set, the refiner's most profitable choice is still to optimize crude selection for production given the controlled product prices and market demands. Thus, control should not encourage the purchase of higher priced crudes simply because their cost can be passed through.

Changing product quality specifications can signify a clear need for increased margins and changes in product price differentials. Many countries around the world are changing product specifications to achieve environmental improvement objectives. Changing product qualities can involve substantial increases in investment costs for facility improvements, and associated increases in operating costs for the refinery to produce the same volume of products.

5.2.1 Future Refinery Facility Investments

As stated previously, decision making on future refinery facility improvements in the Philippines is very difficult because of the uncertainty about future product price differentials and potential energy policy decisions that could shift the relative demand for oil products. This report recommends that policy actions be taken to dampen the growth of diesel fuel, which would impact the refiners' facility choices for the future.

Because of the price and demand uncertainty, no refinery computer model studies have been conducted to determine the most appropriate refining facilities for the Philippines. It is informative, however, to explore the facility options open to refiners to change the mix of products produced. The primary way refiners change product mix is by converting the heaviest fraction of crude oil to lighter products (gasoline and diesel).

The heaviest fraction from the primary distillation unit is the atmospheric tower bottom (360°C+), and this whole fraction is sometimes processed, or is separated into lighter and heavier fractions in a vacuum distillation unit. These fractions are vacuum gas oil (360 - 540°C) and the vacuum tower bottoms (540°C+), and one or both of these streams are processed. Processing choices all involve "cracking" or breaking down larger molecules, but there are also some undesired recombination reactions to heavier molecules (tars and cokes). The cracking processes employ the following conditions to achieve conversion of the feed stream:

- Thermal Process - Heat Only
- Thermal, Catalytic - Heat In Presence of a Catalyst
- Thermal, Hydrocatalytic - Heat, and Catalyst In Presence of Hydrogen

Each type of process can vary in terms of severity - i.e. temperature, pressure and time. There is an increasing progression in cost of processes ranging from thermal to catalytic to hydrocatalytic, but results also improve in terms of conversion and selectivity. Selectivity refers to the degree that desirable products are obtained in the converted material.

The major process alternatives for converting atmospheric tower bottoms (ATB), vacuum gas oil (VGO) and vacuum tower bottoms (VTB) to light products are given in Table 5-7.

The following points will provide perspective in comparing these processes:

- It is easier and less costly to convert VGO than VTB;
- Middle distillates can't be produced without also producing more gasoline;
- An FCC unit is more of a gasoline maker than a middle distillate maker;
- The hydrocracker has the best conversion and selectivity but is most costly; and
- Undesired product yield increases with feedstock boiling range and process severity.

Table 5-7

Yields For Refinery Upgrading Processes (Wt%)

	Thermal Cracker High Dist	FCC High Dist	FCC High Gaso	Hydro-Cracker	Vis-breaker	Delayed Coker
CONDITIONS						
Severity	Moderate	Moderate	Moderate	Moderate	Mild	Severe
Thermal	X	X	X	X	X	X
Catalyst		X	X	X		
Hydrogen				X		
FEEDS	----- Vacuum Gas Oil -----				Atm Twr Bttms	Vacuum Bttms
PRODUCTS						
Ovhd Lt Gas	7.1	7.5	15.2	5.2	2.5	11.3
Lt Gasoline	4.8	0.0	0.0	5.9		
Naphtha(Gaso)	10.8	27.0	47.4	30.7	9.3	19.1
Middle Dist	48.4	38.3	18.8	61.2	14.2	22.0
Bottoms	28.9	25.8	13.0	0.0	74.5	18.8
Coke	0.0	1.5	5.6	0.0		28.8
TOTAL	100.0	100.0	100.0	103.0	100.5	100.0
GASO+DIST	59.2	65.3	66.2	91.9	23.5	41.1
DIST/GASO	4.5	1.4	0.4	2.0	1.5	1.2
INVEST ($bbl/d)	1250	2200	2200	3300	1250	2700

The processes that can make more distillate are visbreaking, thermal cracking and hydrocracking. FCC and coking produce some distillate, but are more suited to increasing gasoline production. Visbreaking is the process that Shell has chosen for the STAR project, and will increase Shell's middle distillate production. It does so by converting heavier material to middle distillates and also by reducing the viscosity of the visbreaker bottoms. This means less distillate material has to be added to the visbreaker bottoms than would otherwise have to be added to the feed stream in order to meet product viscosity specifications. The visbreaker is a relatively mild thermal process and is the least costly of all the process options shown, but the volume of additional distillate product is comparatively small. In an environment of uncertainty about the relative pricing of middle distillates, a visbreaker may be the best choice, but diesel demand growth might indicate that a hydrocracker would be needed to meet future demand mix. However, the

hydrocracker is the most expensive of the process alternatives; its investment cost per daily barrel is roughly three times the cost of a visbreaker, and may also require added investment in hydrogen production facilities. Clearly, a high middle distillate refining gate price would be required to justify investment in a hydrocracker. That is, marginal cost of distillate production would exceed the marginal cost of gasoline production, and consequently, the relative prices of gasoline and diesel would have to reflect those relative marginal costs to provide investment incentive for a hydrocracker project. Currently, regulated prices do not provide adequate incentives for large increases in distillate production capability.

Based on existing refining facilities, increased gasoline production is possible without significant increase in marginal cost. With existing facilities middle distillate production is near the maximum. The addition of the Shell visbreaker will result in only a very modest increase in distillate production. Increasing diesel imports may appear to be the best solution, but high diesel demand is also a problem in the region. For the immediate future, refinery upgrading decisions should await a clearer view of pricing, tax and energy policy decisions, as these will affect demand and relative pricing, factors which will determine the most appropriate future refining facilities for the Philippines.

5.3 Refinery Replacement costs

A rough approximate estimate was made of the replacement cost of the Philippine refinery facilities as planned for 1994. The basis for these rough estimates was the new construction cost for the same size and type of units as are anticipated to exist in 1994, i.e., Petron as it currently exists, Caltex with expansion and Shell with the STAR project. In actual practice, few, if any, refiners in the world would replace all existing equipment, which generally has evolved over a period of many years, with the same number, size, or even type of processes. Technological advances, consolidation of multiple units into single units, different demand patterns, different feedstock scenarios, environmental and social policies, possible joint ventures and many other factors would be considered in any decision if it were necessary to replace existing refineries.

Process units battery limits costs were based on cost curves for a US Gulf Coast location escalated by 40% for a Philippine location. Off-site and support facilities were assumed to be 75% of process battery limits costs. Tankage was estimated to cost 12.50 US$/bbl. Jetty, docks and land costs are very site-specific. Shell indicated that costs for the jetty and docks in its STAR project are $400 million. It was assumed that the replacement cost for Caltex's and Petron's facilities would approximate Shell's cost, and $300 million was used.

The estimated replacement costs for the 1994 Philippine refineries, as planned for 1994, are shown in Table 5-8.

Table 5-8

Facility Area	US $ Millions Caltex	Petron	Shell
Process Battery Limits	241	339	277
Offsite Support Facilities	169	237	194
Tankage	58	128	22
Shell Existing Tankage			42
Total, excluding Jetty, Docks, etc.	480	721	549
Jetty, Docks, etc.	300	300	400

Further details are shown in Table 5-9. Again, these are very rough estimates, and replacement costs in kind do not necessarily correlate with the actual value of an existing refineries.

5.4 Summary and Recommendations

Several cases were developed using the Linear Programming model (LP) described in Chapter 4. The results of these cases quantify the impact of price on the optimum crude selection and optimum product slate for each of the refineries investigated. Cases were also analyzed that forced production of specific products at a non-optimum level to determine the effect on crude selection and economics.

Comparisons of optimum operations as depicted by the LP solutions with that of actual operations were made. Not surprisingly, the optimum solutions indicates more gasoline and less distillate should be produced than was actually the case. This is due to refiners tending to maximize diesel while limiting gasoline to meet local demand. In other words, the refiners strived to meet demand although the controlled price structure indicated more gasoline and less diesel would have been more economical, assuming the additional gasoline could have been sold in the local market. The refiners were attempting to meet the needs of the market at the expense of generating lower margins.

Government controlled prices play an enormous role in supply/demand patterns and, accordingly, the economics of refinery investments. Demand is influenced by price and it is irrelevant to the consumer whether that price results from DOCT, taxes, OPSF, dealer margins or other factors. Economics of supply is partially dictated by netback to the supplier. The controlled low prices for diesel has distorted demand upward while distorting the economics of supply downward.

Refiners cannot make rational decisions on investments without knowledge of future energy policies, ie pricing, of the government. No LP runs were made to define future hardware requirements due to the uncertainty government policy. Economics of conversion hardware to increase diesel production were reviewed and concluded that regulated prices do not provide adequate incentives for large increase in diesel production capabilities.

Rough estimates were made of the replacement cost, in kind, of the three Philippine refineries as planned for 1994: Caltex, $780MM; Petron, $1,021MM; and Shell, $949MM. It is doubtful that many, if any, refineries would be replaced in kind. Thus, replacement cost does not necessarily correlate with actual value.

75

6 The Diesel Dilemma

In the previous two chapters it has been shown that for Philippine refiners to supply a greater fraction of diesel and other middle distillates would mean that diesel would have the highest unit cost of all the refined products. Increased volumes of diesel can be produced by processing more of the most expensive premium crudes or by adding diesel-making processing facilities that are among the most costly equipment both to purchase and operate. On the other hand, Philippine refiners have existing equipment to produce more gasoline.

This chapter will review the impact of past pricing and tax policies of diesel supply and demand. Recommendations are made on adjusting pricing strategies and taxes to improve the diesel supply demand situation.

6.1 Diesel Pricing and the Supply/Demand Imbalance

While the cost of producing more diesel is increasing relative to the cost of producing more gasoline, the consumer prices have been going in the opposite direction. As can be seen below.

TABLE 6.1

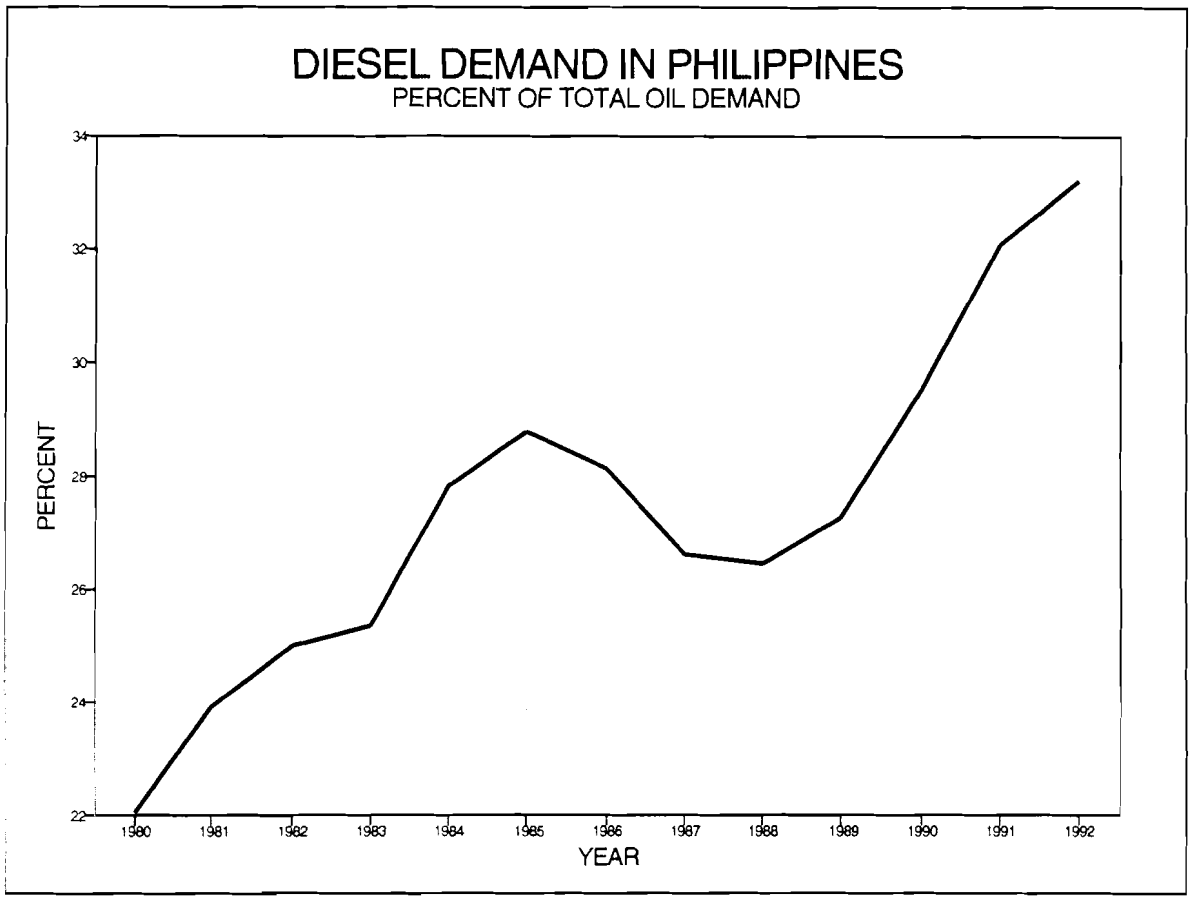
Philippine Oil Product Consumer Prices: Peso/Liter

Annual Average Prices

	Premium Gasoline	Diesel	Price Difference Premium - Diesel
1986	7.12	5.26	1.86
1987	7.15	4.96	2.19
1988	6.95	4.82	2.12
1989	5.91	3.81	2.10
1990	8.09	5.45	2.64
1991	14.69	7.58	7.11
1992	11.69	7.21	4.48

The price difference between premium gasoline and diesel was around 2 *P/L* from 1986 to 1989. The differential rose to over 8*P/L* for a period in 1990 and now stands at 4.*P/L*. The demand for diesel as a percent of the total product barrel is shown in Figure 6.1.

Figure 6-1



In the 1986-1989 period when the Premium Gasoline-Diesel price difference was around 2 *P/L* the diesel demand was declining or flat, but since 1990 the demand for diesel has started to rise rapidly. Surely the higher price differential has been a factor in the diesel demand growing more rapidly, while gasoline demand is declining slightly. The construction of gas turbines for power generation has also been a factor in recent diesel demand growth and will continue to be so in the near future, pushing diesel demand higher.

The problem is obvious, simple economics would say, if diesel is getting more expensive to produce relative to gasoline, then the price to the buyer should be rising relative to gasoline. But in the Philippines, the opposite has been happening: the price of diesel to the consumer has been falling relative to gasoline and as those prices grow apart, a demand shift from gasoline to diesel is occurring.

The pricing pattern for consumer oil products that has been followed in the past few years has been achieved by shifting greater and greater amounts of the tax burden from distillates to gasoline as oil product prices increase.

In many countries around the world the tax on diesel and gasoline are approximately the same and the consumer prices are also fairly close. But in the Philippines the policy has been to price diesel lower than gasoline to provide a lower priced fuel for jeepneys and

buses and hence reduce the economic burden to poorer segments of the population. This policy worked to achieve the desired objective in the 1980's but there are now two important differences compared to the situation in the 1980's:

1) Distillate demands are at a much higher level, where both cost and ability of refiners to supply product needs are problems.

2) The consumer price difference between premium gasoline and diesel has doubled and, if historic pricing patterns are used to adjust product prices, would go higher as crude prices rise.

The distillate supply situation has become quite difficult but will grow dramatically worse unless the current trends are changed. The rate of growth of diesel demand should be dampened so that it grows at no greater rate than the total product barrel. A slightly slower growth rate would be even more desirable. There are two ways of achieving this objective:

1) Decrease the gasoline-diesel price differential

2) Increase the cost of a buying and operating diesel engine vs a gasoline engine vehicle

Implementing both 1 and 2 above is recommended. Increasing the diesel-gasoline price differential was very easy, decreasing it will be quite difficult. A quick reversal to a 2 *P/L* price difference would be a desirable way to achieve the demand growth objective but that is probably not a politically viable action. It is recommended that the price difference be decreased by between .5 *P/L* and 1.0 *P/L*. While this will still leave a price differential that represents a considerable economic incentive to switch from gasoline to diesel it will provide an indication of a change in direction from past consumer pricing trends. The second step is to make the new or replacement diesel engine or diesel engine vehicles more expensive than the comparably sized gasoline powered vehicle. Duty increases on engines and vehicles are recommended for the following:

a. Diesel-run private cars whether imported as complete units or knock-down;

b. Diesel engines for the fabrication of cars, jeeps, jeepneys, or light utility vehicles (LUV's) or as replacement engines for these.

There would be no increase in duty on diesel powered buses. It might also be desirable to moderate the impact on jeepneys operated for public transport, either at the duty level or through a compensating reduction in annual fee registration or a fuel tax rebate (whole or partial). The basic objective is to impose the greatest economic penalty on the private passenger diesel cars, especially a new purchase or conversion, to counter balance the incentive of the fuel price differential.

How much of the increased cost burden should be placed on diesel fuel purchased for public transportation as oil prices rise is a difficult policy issue. It is believed that arresting the current rapid demand growth is a top priority. The practical problem that will be faced in imposing differential duties on diesel vehicles by engine size or functional use is unknown at this time. Also, the distribution of diesel demand by type of user is unknown, specifically how much is used in public transportation. Only when information is available along with the expected degree of success in impacting demand through fuel price vs vehicle cost penalty, will it become possible to make additional adjustments, especially

given the recommendation to move to "specific taxes only" on oil products.

The recommendations for dealing with diesel demand growth are based on the premise that the primary objective of energy and social policy has been to provide low cost public transportation. A low diesel fuel price has been the means of achieving that policy objective. Unfortunately, as experience in the Philippines has demonstrated, when the price of diesel is low compared to gasoline an incentive is created for all vehicle users to consider purchase or engine conversion to diesel power. Increasing use of diesels for private vehicles can then jeopardize the primary objective of the energy/social policy.

There are other alternative approaches to dealing with rapid diesel demand growth which accomplishes the desired social policy. For example, using specific taxes only, diesel tax could be set at 2 *P/L* under the gasoline tax or even at parity with gasoline and then attempt to provide a tax exemption or rebate to buses and public transport vehicles. An effective tax exemption scheme would require that the sales channels for fuel for public transport vehicles are separate with little opportunity for volume to slip through to private usage. A second problem would be the sudden price rise that would be seen by current private diesel owners who would argue that they were being unfairly punished by the government's sudden change in fuel pricing. Basically, a variety of alternatives should be evaluated to find the one with the fewest practical implementation problems that meets the policy objective.

In terms of dealing with the diesel dilemma, it is felt that effectively dealing with the demand side will eliminate a long term supply problem. Two of the Philippine refiners already possess catalytic cracking units which can produce more light products. It makes little economic sense to spend investment dollars for new hydrocracker capacity to make diesel fuel while simultaneously underutilizing the capability of the in-place cracking capacity.

In the short term, the diesel supply problem needs to be addressed as quickly as possible. That can best be accomplished by removing barriers and creating the appropriate price incentives for diesel imports. Specifically the following steps are recommended:

1). The elimination of import duties on crude and diesel product. A higher duty on product than that on crude makes imported product uncompetitive and hence importing diesel is unattractive.

2). Increase the refinery gate prices of diesel relative to gasoline by the Singapore to Philippines product transportation cost. That is, the price of diesel relative to gasoline would be higher in the Philippines than in Singapore. This will require the modification of the SIP basis of calculation while prices are still controlled.

3). Deregulate product imports. New entrants in to the oil market sector could be attracted as importers and distributors. The Subic Bay facility could potentially serve as a port and storage facility for this type of activity.

Item 2 would, of course, be carried out as part of the restructuring of duties and taxes with a shift to specific taxes only. Action on the steps discussed are the first priority steps in the decontrol process and should, in fact, be addressed well before the date of price decontrol.

It should be noted that providing appropriate price incentives for diesel imports will also provide added incentives for domestic refiners to produce more diesel. However, as was shown in Chapter 4, a refinery has a rather steep incremental production cost curve at high diesel production levels, thus the primary source of added diesel supply is expected to be product imports.

6.2 Summary and Recommendations

In summary, the Philippines has had a social policy in which diesel fuel was priced lower than gasoline to provide a lower priced fuel for jeepneys and buses and hence reduce the cost of public transportation for the poorer segment of the population. This policy has caused diesel demand to grow much more rapidly than gasoline. As diesel demand has become a higher fraction of the oil product barrel it has become more difficult for refiners to meet the demand requirement. Attracting diesel import has also been difficult because of the controlled diesel price and the product import duties.

A number of recommendations have been made to remedy the "diesel dilemma":

1) Remove the import duty and replace with a specific tax
2) Increase the refinery gate price relative to gasoline (higher than SIP), but reduce the consumer price gasoline-diesel differential
3) Deregulate product importation
4) Increase duties on new diesel engine and diesel vehicles with lower duties or compensating benefits for public transport vehicles

The objectives of these recommendations are to provide increased diesel supply in the short term and diminish diesel growth rates in the longer term.

7 TAXES ON PETROLEUM

Most countries' tax petroleum and petroleum products at rates that are significantly higher than those applied to the output of other industries or non-petroleum products. Exceptions to this are countries with large crude exports who generally either do not tax petroleum products or tax them at a rather low rate.

In the next chapter the taxes, on petroleum and petroleum products, paid by Philippine consumers are compared with the equivalent taxes paid by the end users in other countries.

7.1 Purpose of Taxes and Duties on Petroleum and Petroleum Products

Taxes are imposed on petroleum and petroleum products by governments for a variety of reasons. These reasons include, but are not limited to: generation of government revenue, effecting social goal, decreasing or shifting demand, protecting industries and improving the environment, and are further defined below.

7.1.1 Generate Government Revenue

Many countries find taxation of petroleum products are a convenient method to generate fairly large revenues without excessively complicated procedures.

7.1.2 Effect Social Goals

Taxation policies may be used to implement desired social goals. One method is to levy heavier tax rates on those products deemed to be luxury or that are primarily consumed by the more affluent population. The products that are considered essential or consumed in large quantities by the less affluent are either not taxed or are taxed at lower rates.

7.1.3 Decrease Demand

Governments may wish to decrease the demand for certain products for various reasons: balance of payments, implement social goals, environmental, etc. Since generally demand for a product decreases as prices rise, an increase in the price of a petroleum product is likely to reduce demand.

7.1.4 Shift Demand

Some petroleum products compete with other petroleum products (as well as non-petroleum products). Examples are diesel versus gasoline, kerosene versus LPG, diesel versus heavy fuel oil, and premium gasoline versus regular gasoline. Governments impose higher taxes on those products for which they wish to dampen demand and lower taxes on competing products.

7.1.5 Protect Industries

Some governments choose to favor selected groups of industries by applying lower tax rates or duties, in order to enhance those industries' competitive position. Some examples are: import duties on crude which give advantage to local exploration and production companies, import duties on petroleum products which are advantageous to local refining and marketing companies, or duties on heavy fuel which make coal and geothermal energy more competitive.

7.1.6 Improve the Environment

Taxes are sometimes enacted on environmentally less desirable products in order to increase the consumer price and thus reduce consumption. Examples are higher taxes or higher duties on higher sulfur content fuel oils and diesels.

7.2 Philippine Taxes and Duties on Petroleum and Petroleum Products

There are several categories of taxes applied to petroleum and petroleum products. Their effect is discussed below.

7.2.1 Current Duty and Tax Structure

The Philippine government imposes three categories of duties and taxes on petroleum and petroleum products. They are: (i) Ad-valorem import duties on crude oil and petroleum products, (ii) a special duty, equal for all products, on the volume of petroleum and its products sold internally, and (iii) a set of taxes, specific to each type of product, also sold internally. Table 7-1 lists the characteristics of these taxes and duties.

7.2.2 Aspects of the OPSF

It should be noted that the amounts of money contributed by the refineries to the OPSF are neither a duty nor a tax, provided these amounts are used in accordance with the purpose for which the Fund was set up: to compensate the oil companies when crude prices are higher than the reference price level reflected in the refined products' prices. It is similar to a trust fund which is used to stabilize product prices.

There have been suggestions to use the OPSF for purposes other than petroleum product price stabilization (e.g. volcano relief, assistance to NPC, contributions to the General Fund, etc.). Use of the funds for the above mentioned purposes would be tantamount to making such withdrawals a tax since the funds would not be available to reduce the costs, when the price of petroleum rises.

Table 7-1
DUTIES AND TAXES ON
PETROLEUM AND PETROLEUM PRODUCTS

		Rate	Unit	Basis
(a)	Regular Import Duty			
	Crude Oil	19.0%	%	c.i.f.
	Petroleum Products	29.0%	%	c.i.f.
(b)	Special Duty			
	All Products	1.00	Peso/liter	All Products sold
(c)	Specific Taxes			
	Premium Gasoline	2.52	Peso/liter	Premium gasoline sold
	Regular Gasoline	2.28	Peso/liter	Regular gasoline sold
	Jet	2.38	Peso/liter	Jet sold
	Kerosene	0.50	Peso/liter	Kerosene sold
	Diesel	0.45	Peso/liter	Diesel sold
	Fuel oil	0.00	Peso/liter	None
	LPG	0.00	Peso/liter	None
	Asphalt	0.56	Peso/liter	Asphalt sold
	Thinners	0.00	Peso/liter	None

7.2.3 Analysis of Product Price Buildup March - 1992

The analysis in Table 7-2 shows the make up of the taxes and duties included in prices of petroleum products to the consumer. The analysis is applicable to conditions existing in March and April 1992 for the Metro Manila area.

Three categories of ERB established prices are shown:

(a) The established base price[1] which includes ad-valorem import duties

[1] The base price is established by the ERB taking the direct oil company take (DOCT) into consideration. The DOCT first established on January 14, 1971 and has undergone numerous changes since then, although the concept it represents is basically the same. Even though the principle guiding the determination of DOCT is cost recovery, the changes to it have been limited to the changes in the cost of crude importation, excepting the partial increase of 2.5 centavos per liter that was allowed in the recovery of operating expenses in May, 1986. The DOCT is adjusted every two months in accordance with the change of the cost per barrel of crude imports, compared to the previous two month period. The crude cost adjustment is based on Singapore import parity and the sales of products in the corresponding period.

(b) The approved posted price which is equal to the base price plus special duties, specific taxes, and the OPSF component

(c) The end user price which is the posted price plus hauling and the allowed dealer markup for gasolines, kerosene, and diesel

Table 7-2

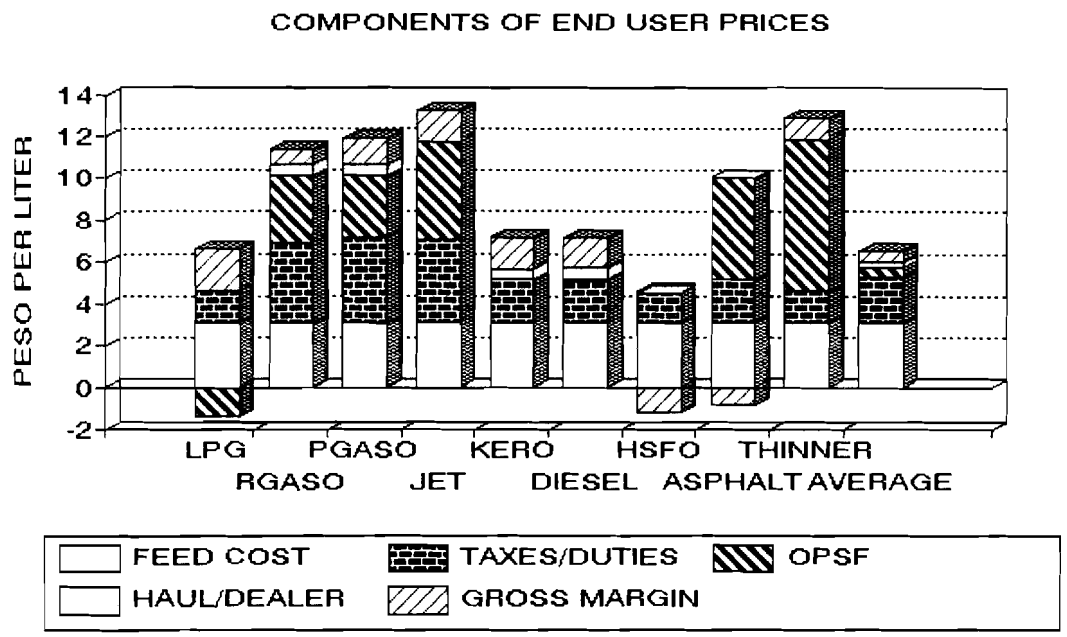
Analysis of ERB Pricing for March 1992
Pesos Per Liter

	LPG	RGASO	PGASO	JET	KERO	DIESEL	HSFO	ASPHALT	THINNER
1. ERB PRICE BASE	5.67	4.42	4.91	5.20	5.23	5.18	2.47	2.79	4.75
2. SPECIAL DUTY	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
3. SPECIFIC TAX		2.28	2.52	2.38	0.50	0.45		0.56	
4. OPSF	-1.41	3.25	3.00	4.81	0.04	0.13	-2.02	4.90	7.25
5. POSTED PRICE	5.26	10.95	11.43	11.39	6.77	6.76	3.45	9.24	13.01
6. HAULING		0.09	0.09		0.09	0.09			
7. DEALER MARKUP		0.46	0.47		0.43	0.45			
8. END USER PRICE	5.26	11.49	12.00	13.39	7.30	7.30	3.45	9.24	13.01
9. ERB TARGET		11.50	12.00						
10. INDUSTRY VOL%	6.19	3.71	10.17	1.20	4.52	38.78	34.79	0.47	0.17
DUTY TAXES & OPSF									
DUTY ON CRUDE	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
SPECIAL DUTY	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
SPECIFIC TAX		2.28	2.52	2.38	0.50	0.45		0.56	
TOT. TAXS & DTY	1.56	3.36	4.10	3.96	2.08	2.08	1.38	2.14	1.38
OPSF	-1.41	3.25	3.00	4.81	0.04	0.13	0.02	4.90	7.25
TOTAL GOVT. IMPOSED ADD ON	0.17	7.11	7.10	8.77	2.12	2.16	1.56	7.04	8.84

Figure 7-1 presents the components of end user prices for each product as well as of the weighted average product for the March 1992 ERB data.

54

Figure 7-1



7.2.4 Characteristics of the Revenue Produced by Taxation

Even though it may be difficult to reconstruct the rationale that guided the original establishment of the duties and taxes imposed on petroleum and petroleum products, it is possible to analyze some of their main features and to conjecture into which of the purposes listed in Section 7.1 they fall under.

(a) The 19% ad-valorem duty on imported crude oil could be construed to have two purposes: (i) protect the Philippine oil producers, and (ii) produce revenue.

The 19% duty on imported crude produces a differential which was approximately 0.58 pesos/liter (3.55 US$/barrel) in favor of the Philippine produced crude. For simplification and illustration, the duty on crude (as well as the cost of crude) has been allocated equally to all products. If the price of the Philippine produced crude is equated to the landed cost, plus duty, of the imported oil, the differential would result in a considerable advantage to the local producer and may or may not be sufficient to cover the risks and production costs associated with local production.

However, since local crude production is less than 5% of the total consumption, the promotional aspect of the 19% duty is relatively small, and it could then be said that its main purpose is to generate government revenue.

85

(b) Whether the 29% ad-valorem duty on imported petroleum products could be deemed to protect the local producer depends on whether the local production costs (including a reasonable return on the investment) are sufficiently low to allow pricing the local product in competition with the imported equivalents. Taking a very simplistic situation, in which the finished product has the same volume as the crude used in producing it, there would be a margin of only 10% (29 - 19%) to cover production costs and provide for a reasonable return.

Since the margin to cover production costs and an adequate return allowed by the import duty on petroleum products does seem to be sufficient, it can be inferred that the 29% duty on imported products is not sufficient to encourage local production and that therefore it could be said that its main purpose is to generate government revenue.

(c) Since the Special Duty of one peso per liter is applied to all products sold in the Philippines, its main purpose is to generate government revenue.

(d) In addition to generating government revenue, it may be argued that specific taxes on each of the products can also fulfill the following purposes: (i) effect social goals, (ii) shift the demand from certain products to other products, and, to a small extent, affect the environment.

The following example will illustrate how some of the above principles operate. Since the specific tax on diesel is approximately 1/5 of the tax on gasoline, the transportation consumer may prefer to invest in a diesel-driven vehicle, instead of a gasoline-powered one, because he/she feels that the additional cost of the diesel vehicle would be offset by the much lower cost of fuel, over the life of the vehicle. Thus the lower specific tax on diesel would have the effect of shifting the demand from gasoline towards diesel. A secondary effect to the consumer decision would be that the resulting transportation costs to the consumer that provides transportation services (but not necessarily to the economy as a whole) would also be lower and thus that the tariffs for transportation would also be lower. This, in turn, will result in a corresponding decrease of the cost of the end products used by the public at large - this could be construed as a means of achieving a social goal to reduce the cost of living.

The use of specific taxes to improve the environment may not have such a direct result as some of the methods used to achieve other purposes. As a hypothetical example we could mention the fact that no specific tax is applied to LPG. Thus there could be an incentive to use LPG in transportation, since it produces less pollutants than alternate fuels. However, it may be impractical to use LPG because of the absence of an infrastructure which would assure suitable distribution of the product and the availability of equipment that could adequately utilize LPG.

Table 7-3 displays the weighted average of the cost components of petroleum products for the period under consideration. It will be noted that the Regular Import and the Special duties increase the cost of all products to the consumer since the Regular Import duty is applicable to the feedstock from which all products are manufactured and the Special duty is applied to

every product sold. This is equivalent to having a tax of 1.58 pesos per liter ($9.64 per barrel) on every product. Specific taxes averages 0.59 pesos per liter (US$ 3.47 per barrel). Thus, 74% of the taxes and duties are across the board on all products and only 26% are selective to specific products.

Table 7-3
Weighted Average of Cost Components
for Petroleum Products

	Peso/liter	US$/bbl	%
Crude	3.09	18.83	47
Import Duty	0.59	3.55	7
Special Duty	1.00	6.09	15
Specific Taxes	0.57	3.47	9
Hauling	0.05	0.32	1
Dealer Markup	0.26	2.58	4
OPSF	0.48	2.90	7
Refiner/Marketing Margin	0.53	3.21	8
End User Price	6.56	39.95	100
Memo: Taxes & Duties	2.15	13.15	33

7.2.5 Revenue Generation Options

Taxation on petroleum products can be varied to produce different results. The category and mix of the results from taxation can take many forms. Two hypothetical examples are given below to describe the effect of taxation. In these examples the price of the products to the consumer is not changed, so that the elasticity of demand need not be considered.

Constant Government revenue can be generated while maintaining the same consumer price for each product as well as constant company take (DOCT) by restructuring the duty and tax bases, as shown in Table 7-4.

In the example in Table 7-4 it was arbitrarily assumed that the local crude producers needed little protection from imported crude and a duty of 2% would be adequate to cover administrative costs of customs. For simplification, OPSF was included with duties and taxes even though it is fully recognized that OPSF is not a tax. No adjustment for the positive or negative effects of the OPSF are shown, so as not to detract from the principles being illustrated of tax restructure.

TABLE 7-4
Government Revenue and OPSF
Actual and Reconstructed
Millions of Pesos

	Duty on Crude	Spec ial Duty	Spec ific Tax	Total Govt Rev/u	OPSF Rev-enue	Total Govt Add
MARCH 92						
LPG	81	139		220	-196	23
RGASO	49	83	190	322	271	592
PGASO	133	228	575	935	684	1 619
JET	16	27	64	107	129	236
KERO	59	101	51	211	4	215
DIESEL	506	869	391	1 767	111	1 878
HSFO	454	780		1 234	-15	1 219
ASPHALT	6	10	6	22	51	74
THINNER	2	4		6	27	33
TOTAL	1 306	2 241	1 267	4 823	1 066	5 889
RECONS-TRUCTED						
LPG	9		15	23		23
RGASO	5		587	592		592
PGASO	14		1 605	1 619		1 619
JET	2		234	236		236
KERO	6		209	215		215
DIESEL	53		1 824	1 878		1 878
HSFO	48		1 171	1 219		1 219
ASPHALT	1		73	74		74
THINNER	0		33	33		33
TOTAL	137		5 752	5 889		5 889

Table 7-5 compares the component make up of each product price for the tax structure existing in March 1992 with an assumed new tax structure designed to assign specific taxes to each product while maintaining constant end user prices for each product.

Table 7-5

Summary of Government Revenue and OPSF
Millions of Pesos

	LPG	RGASO	PGASO	JET	KERO	DIESEL	HSFO	ASPHALT	THINNE	TOTAL
MARCH 1992 PROCEDURES BASED ON JAN/FEB 1992 VOLUMES										
Government Revenue:										
Crude Duty	81	49	133	16	59	506	454	6	2	1,306
Special Duty	139	83	228	27	101	869	780	10	4	2,241
Specific Taxes	0	190	575	64	51	391	0	6	0	1,277
Total Government Taxes	220	322	935	107	211	1,767	1,234	22	6	4,824
OPSF Collections	(196)	271	684	129	4	111	(15)	51	27	1,066
Total Government Add-	24	593	1,620	236	215	1,877	1,219	73	33	5,890
RESTRUCTURED DUTIES, TAXES AND OPSF										
Government Revenue:										
Crude Duty	9	5	14	2	6	53	48	1	0	138
Special Duty	0	0	0	0	0	0	0	0	0	0
Specific Taxes	15	587	1,605	234	209	1,824	1,171	73	33	5,751
Total Government	24	592	1,619	236	215	1,877	1,219	74	33	5,889
OPSF Collections	0	0	0	0	0	0	0	0	0	0
Total Government Add-	24	592	1,619	236	215	1,877	1,219	74	33	5,889
SALES, JAN/FEB 1992	873	524	1,434	169	637	5,468	4,905	66	23	14,099
MARCH 1992 PRICES AND COST COMPONENTS										
Pesos Per Liter										
End User Prices	5.26	11.49	12.00	13.39	7.30	7.30	3.45	9.24	13.01	
Crude Duty	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	
Special Duty	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
Specific Taxes	0.00	2.28	2.52	2.38	0.50	0.45	0.00	0.56	0.00	
Haul Allowance	0.00	0.09	0.09	0.00	0.09	0.09	0.00	0.00	0.00	
Dealer Margin	0.00	0.46	0.47	0.00	0.43	0.45	0.00	0.00	0.00	
OPSF	(1.41)	3.25	3.00	4.81	0.04	0.13	(0.02)	4.90	7.26	
Oil Company Take	5.09	3.84	4.33	4.62	4.65	4.60	1.88	2.21	4.17	
REALLOCATION OF GOVERNMENT IMPOSED ADD-ON TO MAINTAIN PRICES, DOCT AND ENHANCE GOVERNMENT REVENUE										
End User Prices	5.26	11.49	12.00	13.39	7.30	7.30	3.45	9.24	13.01	
Crude Duty	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	
Special Duty										
Specific Taxes	0.11	7.05	7.04	8.71	2.06	2.10	1.50	6.98	8.78	
Haul Allowance	0.00	0.09	0.09	0.00	0.09	0.09	0.00	0.00	0.00	
Dealer Margin	0.00	0.46	0.47	0.00	0.43	0.45	0.00	0.00	0.00	
OPSF										
Oil Company Take	5.09	3.84	4.33	4.62	4.65	4.60	1.88	2.21	4.17	

Table 7-5 also shows the amount of government revenue that is generated by each product when using the March 1992 structure as well as for the restructured tax bases. The total government revenue for each product as well as the grand total are identical for the two bases.

It should not be inferred that this specific tax structure is recommended. Rather, it is an example to show that taxes can be structured to meet other goals and at the same time maintain government revenue. Chapter 11 gives other examples of setting tax rates at levels more compatible in reaching perceived goals of pricing, by using a more rigorous mathematical approach.

7.3 Possibilities for Restructuring of Duties and Taxes

The determination of the need to restructure duties and taxes on petroleum products must be guided by the clear identification of the goals of the subsector and by the expectations of how any changes in the pricing of the products (resulting from taxation) would modify their consumption (elasticity of demand). The goals themselves are a result of the interpretation of the overall Philippine energy policy. Some of the goals that should be considered are:

- Government revenue requirements
- Social aims
- Demand management
- Industry protection
- Protection of the environment

As part of the present study, the DOE has been provided with sophisticated computerized simulation models that will enable it to better predict the effects to be expected from changes of taxation that would be designed to respond to any of the above goals that are established for the subsector.

There are some selective options for taxation that can be viewed at a micro level and which would not have a decisive bearing on the subsector's policy but would still meet specific tax goals. Thus they could be implemented in the short term. Some of these options are:

- There are good arguments for the elimination or reduction of the ad-valorem import duty on crude:

  (a) The duty on crude imports tends to increase the price of all products in the same manner as increased crude prices do.

  (b) There is no apparent need to protect local crude producers because: (i) local producers have the inherent advantage of low transportation costs for supplying the local refiners, and (ii) there is no evidence that their production costs should be very different from those experienced by neighboring producers. Thus, unless explicit reasons

are identified for giving them import protection on their production, there is no evident reason for this protection.

Thus, consideration should be given to totally eliminate the ad-valorem import duty on crude (or at least reduce it to the level required to cover government costs in administration of customs on petroleum).

- Unless it is desired to have a fully free market, the level of the ad-valorem import duty on petroleum products should be set to permit non-refiners access to the Philippine market while allowing some degree of protection to the Philippine refiner to obtain a fair return on invested capital. This protection should be granted only to the extent that the Philippine refiner maintains acceptable efficiency level in its operations.

- A prompt decision is required to solve an existing situation where some taxes are in conflict with tax aims: taxation on diesel. For social reasons, taxes on diesel have been kept low so that the price of diesel is lower, relative to gasoline's. This has created a high demand for diesel, such that its supply is uneconomic and the corresponding demand management goal is in chaos. Both goals need to be reviewed jointly and a compatible, non-conflicting tax structure needs to be established to obtain a reasonable balance between social purposes and a shift of the demand to more economically sound products. Continued distortion of diesel prices can only lead to further shortage of supply and, ultimately, disaster.

- On the surface there would appear to be a conflict between taxation on the fuel used in the generation of electricity. The crude from which the fuel for power generation is derived and subject to import duty and there is a special duty of 1.00 peso per liter on all products. However, duty drawback is given on all fuel used for power generation. In this manner the "hidden" taxes (ie taxes on fuel used in its generation) on electricity is avoided and the amount of taxes deemed appropriate by the government for electricity is applied directly rather than indirectly.

7.4 Summary and Recommendations

Taxes are imposed on petroleum feed stocks and products with one or more of the following objectives:

1. Generate government revenues
2. Effect social goals
3. Decrease demand
4. Shift demand
5. Protect industries
6. Improve the environment

Petroleum is taxed in the Philippines in three ways;

1. Import duties of 19% on crude and 29% on products,

2. Special duty of 1.00 peso per liter on all products, and

3. Specific taxes on selected products. In addition, product prices are adjusted both up and down by application of the OPSF, although the OPSF is not a tax.

Taxes and duties equate to about one third of the consumer price for products, on average. About one half of the consumer costs reflects the feedstock costs and the balance covers the refining, marketing, hauling and dealer costs and profits.

The current tax and duty structure appear to be mostly non-selective as 74% of the taxes/duties are applied equally to all products and only 26% are specific taxes on selected products. It has been illustrated how the government revenue from petroleum taxes/duties can be held constant while redistributing the taxes and duties selectively over the various petroleum products.

It is recommended that the taxes and duties on petroleum be restructured in a manner to target specific products for various levels of taxes which more clearly reflects the government's multiple goals in petroleum taxation. Specific recommendations are presented in Chapter 15, Implementation of Oil Price Decontrol.

8 REFINING AND MARKETING: RETURNS, PROFITABILITY, AND MARGINS

8.1 Development of the Petroleum Industry

Traditionally, the refining and marketing segment of the oil industry has not provided as attractive returns to the investors as have the exploration and production segments. The large oil companies explored and found large reserves of crude oil. These companies had the choice to either develop these reserves and process the crude through their own refining and marketing divisions or sell to other companies that had insufficient crude production to fully satisfy their refineries' requirements. In order to provide more secure outlets for their production potential the crude producing companies developed product markets and built refineries to supply those markets. The total integrated economics from exploration through product sales were considered in these investment decisions. The intense competition to secure outlets for crude production led to lower product prices in attempts to gain or maintain market share with resultant lower margins and profits for the refining and marketing segments of the industry.

The resultant lower product prices affected those refining and marketing companies with inadequate or no crude production. However, these companies managed to survive and prosper through development of special niches, innovative marketing techniques, refinery efficiencies, diversification, and less overhead than some of their larger integrated competitors.

As a result of the Organization of Petroleum Exporting Countries (OPEC) exerting its influence in the 1970's the control of crude production was taken away from the crude producing companies. This was followed by multiple increases in crude and product prices which led to a significant decrease in demand for petroleum. As a consequence of the decrease in demand for products an excess of refinery and marketing capacities resulted. Rationalization of this surplus contributed to lower returns from refining and marketing operations.

Worldwide environmental concerns have required massive expenditures in refineries and marketing facilities. Additional moves to improve the environment will require significant investments and increased operating expenses in the future. The industry has not been fully successful in recovering all of the additional costs.

8.2 Oil Companies' Returns on Sales, Assets, and Equity

The return on sales, assets and equity for the Philippine oil company are compared with the results of two groups of six international majors and eight US companies.

8.2.1 Returns of Philippine Oil Companies

Table 8-1 shows the average rates of return of the Philippine oil companies, as calculated from their financial statements over the five year period 1987 through 1991.

Table 8-1

Rates of Return of Philippine Refineries

	Caltex	Petron	Shell	Industry
Return on Sales	2.0	3.2	3.4	2.9
Return on Assets	3.5	4.6	4.6	4.3
Return on Equity	21.1	23.0	14.5	18.7

The specific yearly data for each oil company is presented in the Appendix as Table X-1. The respective return data is depicted graphically in Figures X-1, X-2, and X-3 of the same Appendix.

The first increase in company netback (DOCT) since 1986 was granted by ERB in October 1992. This increase averaged 0.12 pesos per liter, about 2% of consumer price. As shown in Table X-1 of the Appendix, the return on assets for the Philippine industry for 1990 and 1991 was 4.1% and 6.4%, respectively. Had the 0.12 P/L higher prices been in effect for all of 1991 the return on assets would have increased to 8.4%. Similarly, had the increase been in effect for all of 1990 and 1991, the average return on assets for the two year period would have been 7.1% versus the actual of 5.1%. Return on sales would have been 4.2% versus 3.0%, and return on equity would have been 29.7% versus 21.2% if the increases were effective for 1990-91. Summarizing, a 0.12 peso/liter increases return on sales by 1.1%, return on assets by 2.0% and return on equity by 8.5%, based on actual data for 1990-91 (slight differences from above due to rounding).

Care should be taken to interpret the results, since the following distortions may be present in the data:

(a) Sales figures include taxes which inflates the revenue over the actual net realizations by the companies for their products and, thus, reduces the Return on Sales percentages.

(b) Property plant and equipment are substantially carried at appraised values and are reflected in total assets accordingly. Thus the reported assets are somewhat above historical costs and the Return on Assets is therefore reduced from that would result if it were based on historical costs. Reporting returns on adjusted appraised values is more appropriate, taking into consideration inflation and currency devaluation.

8.2.2 Returns of Oil Companies in Other Countries

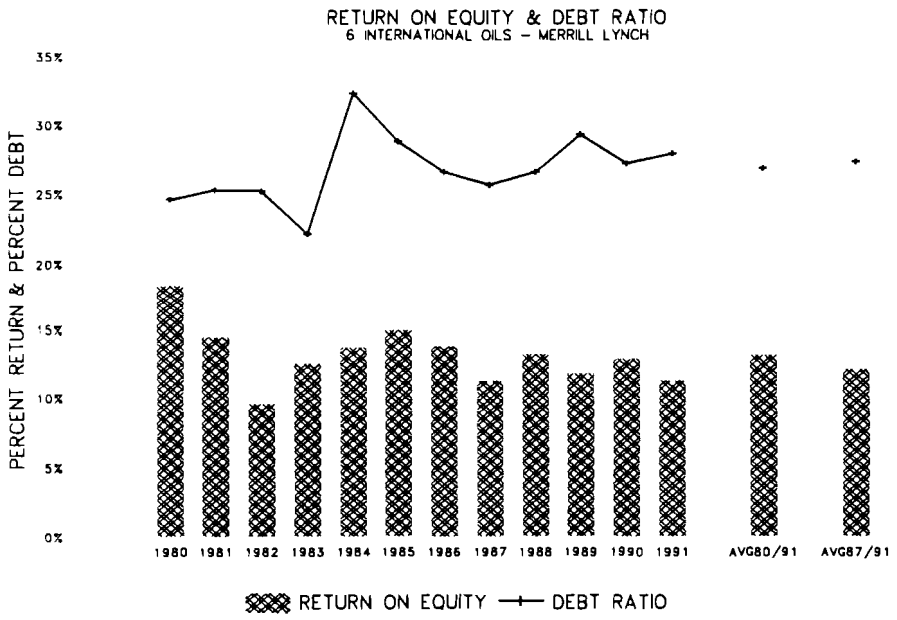
Investors usually are reticent to release their expectation for return on new investments, unless this information is required by regulation or by financing or lending institutions. This is because each investor may have

a different way to appraise the risks entailed with a project and, consequently, would have a different goal for the return to be derived from it. Although many companies wish to identify and report, at least internally, the return on each business segment, these evaluations are not generally available to the public.

Customarily corporate returns are reported on shareholder equity. Returns on total assets can also be calculated but returns on net employed capital are less frequently reported in data available in the public domain. Returns on specific business segments or divisions are seldom available.

Figure 8-1 is based on data on the return on equity for the six major international oil companies (BP, Chevron, Exxon, Mobil, Shell, and Texaco). The weighted average annual returns on equity for the six companies are exhibited in Figure 8-1 for the years 1980 through 1991. The weighted average return on equity was 13.2% for the period 1980-1991. The average return for the period 1987-1991 was 12.1% on equity. All data are based on total corporate return. Data were unavailable to develop the return on only the refining and marketing divisions. The exploration and production divisions of oil companies generally generate higher returns than those from the refining and marketing divisions.

Figure 8-1



BEST AVAILABLE COPY

95

The debt/equity ratio, i.e., debt divided by equity plus debt, is also plotted on Figure 8-1 as a matter of interest. Equity made up 40% of the total assets for the four U.S. international oil companies at the end of 1991.

The "Oil & Gas Journal" (O&GJ) presents annual financial and operating data on the 300 largest oil and gas companies operating in the United States. A data base was created and used to determine yearly returns on sales, total assets and equity for selected companies from 1987 through 1991.

Two groups of data were interpreted:

(a) Data for the U.S. operations (only the same six international oil companies displayed in Figure 8-1) was aggregated. It should be noted that the results of this aggregation gave a series of somewhat different returns on equity (as previously depicted in Figure 8-1) since the O&GJ includes only the US companies of the Royal Dutch/Shell Group and BP (Shell and BP(USA)) as opposed to the worldwide operations reported in the Merrill Lynch data.

(b) Data was also aggregated for eight other large US oil companies with significant refining and marketing divisions. These were: Amerada Hess, Amoco, ARCO, Ashland, Kerr-McGee, Phillips, Unocal, and USX-Marathon Group.

8.2.3 Comparison of Returns of the Philippine Companies with Other Countries

Table 8-2 compares the returns of the three Philippine oil companies with those of other companies for the 1987-1991 period.

The 2.9% return on sales for the Philippine companies is significantly lower than that of the other two groups. All three groups have some taxes included in their sales figures and therefore the total revenue is inflated by the amount of these taxes. In most cases the two non-Philippine groups have a much larger spectrum of integration, ranging from crude production to chemicals. Thus, the margins on some of these sales include crude production margin as well as refining and chemical margins. Some of the sales are also of crude oil, rather than product sales. Return on sales for each of the three groups are presented in Figure 8-2 for the five year period being considered.

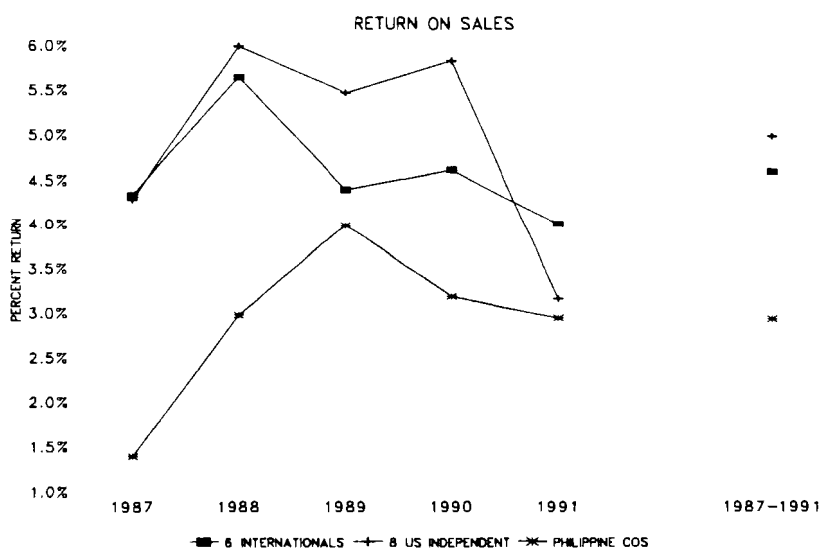
Table 8-2

Comparison of Rates of Return of Philippine, U.S. and International Oil Companies

	Return on		
	Sales %	Assets %	Equity %
Philippine (3)	2.9	4.3	18.7
Internationals (6)	4.6	5.4	11.8
Independents	5.0	4.8	15.5

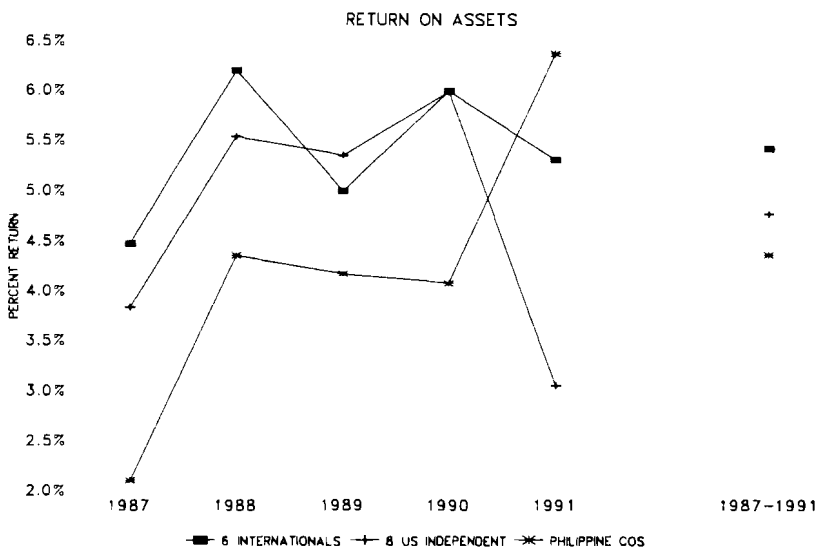
Returns on assets are probably the most indicative of the relative profitability of the three groups. The return on assets for the three Philippine companies is 1.1% lower (a relative 25%) than that of the six internationals and about 0.5% lower (a relative 12%) than that of the eight US independents. The other two groups have more sophisticated operations which include exploration and production, which generally generate higher returns than refining and marketing.

Figure 8-2



BEST AVAILABLE COPY

Figure 8-3



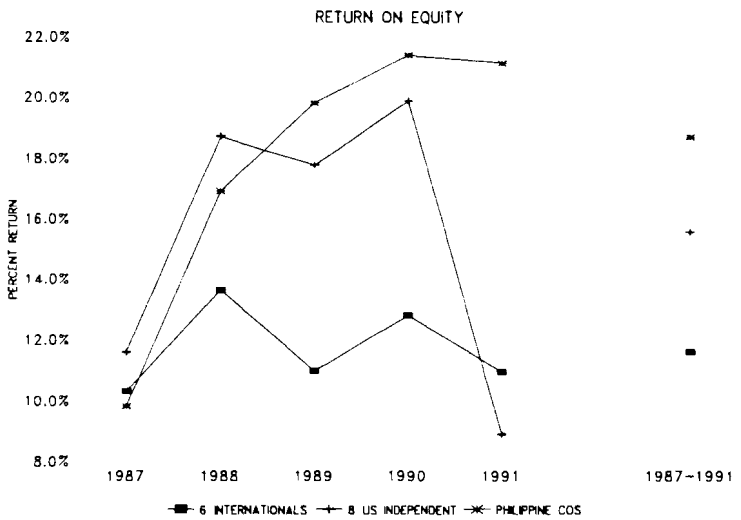
Any on-going business must generate acceptable returns on assets in order to replenish old equipment, maintain its operations and prepare for required future demands of production and environmental regulations.

Without adequate returns on existing investments, additional investments cannot be made. Annual return on assets is depicted in Figure 8-3 to each group.

The Philippine industry average return on equity of 18.7% compares favorably with those reported for the six international companies (11.8%), and for the eight independents (15.5%). The return on equity is highly influenced by decisions on debt structure. The choice, or perhaps requirement, of a high debt to equity ratio increases the leverage on the return on equity. Of course the risk is also increased due to the interest payments on the debt. Return on equity for each group for each of the five years is shown in Figure 8-4.

BEST AVAILABLE COPY

Figure 8-4



8.3 Refining and Marketing - Profitability and Margins

The profitability and margins of Philippine refining and marketing companies are compared with those of international groups.

8.3.1 Profitability and Margins - Philippine Companies

Pro forma profitability on the products produced by the refineries of the Philippine oil companies was estimated using data made available by DOE and the Philippine oil companies.

Monthly data were available for 1990 and 1991 for each company. They included:

- **Production by product**
- **Direct Oil Company Take (DOCT)**
- **Crude cost**

Annual data were available as follows:

- **Refining expenses**
- **Marketing expenses**
- **Freight under recovery**

Revenue was calculated multiplying the production data times DOCT product prices for each month. Crude cost per barrel for each company, including transportation, insurance, duty, ocean loss, and wharfage, was multiplied by the unit crude charge to give crude costs each month. The gross margin is revenue less crude cost.

BEST AVAILABLE COPY

The processing fee for the Caltex crude processed by Petron was estimated to be 120% of Petron's costs on a per barrel basis. Refinery and marketing expenses as well as the freight under recovery were deducted to give the earnings before interest and taxes (EBIT).

The Foreign Exchange (FOREX) Advantage was estimated to be 2.75% of the cost of crude based on the assumption shown in Table 8-3.

Table 8-3

Assumptions Taken in the Calculation of the FOREX Advantage

	Days	Percent
FOREX Coverage	180	2.00
Loan from Banks	150	5.50
Placement Credit	150	14.5
Supplier Credit	30	0.00
Effective Annuzlied Advantage		2.75

Table 8-4 displays salient data based on crude charge only. All produced at the refinery are assumed to be sold at DOCT prices. Imports and exports have been ignored in order to arrive at refinery and marketing margins from crude actually processed.

Table 8-4

Earnings Before Interest and Taxes (EBIT)
Crude Charge Only
Average 1990-1991

US$ per Barrel of Crude Charged				
	Industry	Caltex	Petron	Shell
Gross Margin	2.15	3.17	1.84	1.65
Process Fee, Cost/(Revenue)	0.00	0.09	-0.05	0.00
Refining Expenses	0.88	1.13	0.65	1.04
Marketing Expenses	1.24	1.22	0.90	1.88
Freight Under Recovery	0.13	0.12	0.12	0.18
Subtotal	-0.10	0.61	0.22	-1.45
FOREX Advantage	0.64	0.65	0.62	0.67
Net EBIT	0.53	1.26	0.84	-0.78

The company differences on the Gross Margins can largely be explained by the differences in yields as presented in Table 8-5. The yields reflect the complexity of the refinery and the quality of the crude charged. Gross Margins are presented in Figure 8-5 for each company and the industry, for 1990, 1991 and the average of the two years.

Table 8-5

Yields Based on 1990-91 Total Refinery Production

	Industry	Caltex	Petron	Shell
AVTUR	4.3	4.3	4.4	4.3
PGASO	12.5	16.7	11.3	10.3
RAGSO	4.0	5.1	2.5	5.5
KERO	4.5	6.3	3.1	5.4
DIESEL	30.2	35.6	24.5	35.0
FUEL OIL	31.9	20.1	24.5	35.0
PROCESS GAS	0.0	0.0	0.0	0.0
LPG	3.5	4.2	3.7	2.3
ASPHALTS	0.4	0.0	0.8	0.0
SOLVENTS	0.8	0.0	0.4	2.6
NAPTHA	3.4	0.8	6.7	0.0
AVGAS	0.0	0.0	0.0	0.0
PROPYLENE	0.0	0.0	0.0	0.0
INTERMEDIATES	0.7	2.4	0.0	0.0
REF/FUEL & LOSS	3.7	4.4	3.7	3.1
TOTAL	100.0	100.0	100.0	100.0

Tables VIII-2 and VIII-3, in the Appendix, present results of the interpretation of the above pro forma data for each of the oil companies and for the industry as a whole for 1990, 1991, and for 1990/91 combined. Table VIII-2 gives the results in total pesos and dollars while Table VIII-3 states the same information in both pesos per liter and dollars per barrel.

Figure 8-5

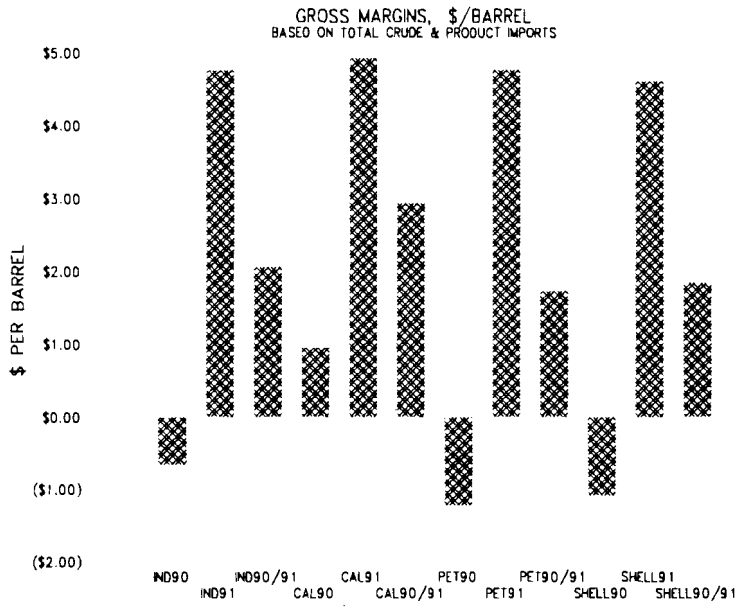
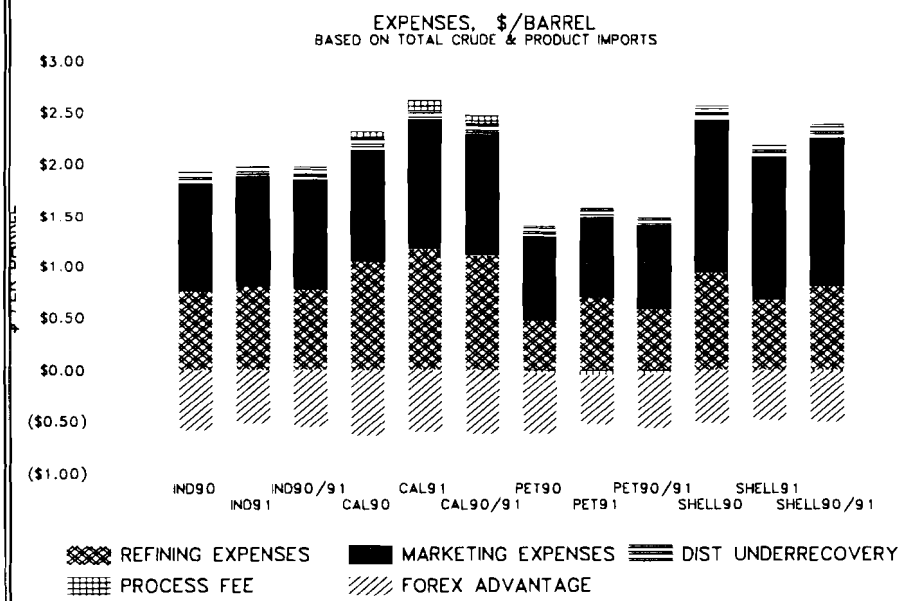


Figure 8-6



102

Expenses are graphed in Figure 8-6. Data backing up the graphs are presented in both pesos and dollars as well as pesos per liter and dollars per barrel in Table X-2 and X-3 of the Appendix.

It should be emphasized that these data are based on crude charged for each company's own account only. Caltex data includes crude processed for its own account at Petron, whereas Petron data excludes the Caltex crude which Petron processed. Also, the data excludes all products imported for resale and exports. Therefore the marketing and freight under-recovery expenses are somewhat overstated when based on crude charge only. Further, all of the refinery production was priced at DOCT when actually some of the production was exported at lower than DOCT values. Thus it can be said that the the gross margins are overstated.

These data also do not include interest expenses incurred for working capital or other interest, except for the net advantage of FOREX coverage. Other corporate cost elements, such as income taxes, or corporate income elements, derived from operations other than that realized from the sale of products derived from crude processed were not included. A direct comparison of these pro forma data to total corporate after tax profits are therefore not meaningful. *The data were developed for use in comparing Philippine operations to that of other countries on a similar basis.*

A different interpretation of the data was calculated to take into account exported and imported products. The margins from processing crude and selling all production at DOCT prices was adjusted to reflect the impact of imported products and exports. All imported products were assumed sold at DOCT prices. Cost of imports was based on c.i.f. data furnished by DOE and multiplied by 130% to include the 29% duty and other miscellaneous costs. All exports were costed at DOCT prices and valued at f.o.b. prices as furnished by DOE. The margins on imports/exports (many instances negative) were added to that calculated from crude processing presented earlier. The divisors used were the sum of crude processed and products imported. The margins and expenses on this basis are shown in Table 8-6.

Table 8-6
Earnings Before Interest and Taxes (EBIT)
Crude Charged Plus Imported Products

US$ per Barrel of Crude Charge Plus Imported Products	Industry	Caltex	Petron	Shell
Gross Margin	2.06	2.94	1.73	1.85
Process Fee	0.00	0.09	-0.05	0.00
Refining Expenses	0.77	1.10	0.58	0.80
Marketing Expenses	1.09	1.19	0.81	1.45
Freight Under recorvery	0.12	0.11	0.11	0.14
Subtotal	-0.07	0.45	0.28	-1.11
FOREX Advantage	0.56	0.63	0.56	0.52
Net EBIT	0.49	1.08	0.89	-0.02

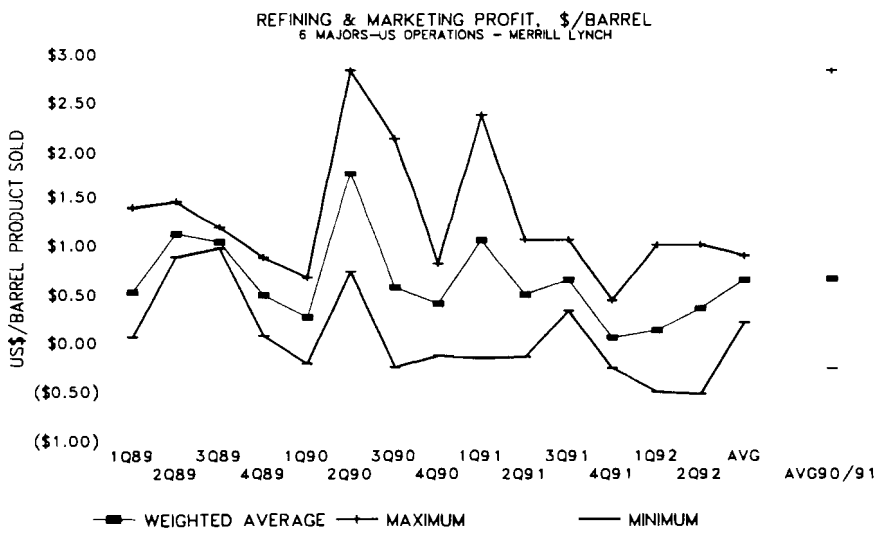
8.3.2 Profitability and Margins - Other Countries

Specific information on the profitability of the refining and marketing divisions of companies explicitly comparable to the three oil companies in the Philippines is not available. However some data has been developed which should give adequate insight into the experience and history of the profitability in other countries and the use of this data should be helpful in the analysis of the profitability of the Philippine companies.

The gross contributions to corporate profitability by each of the divisions of the integrated oil companies are included in the companies' quarterly and annual reports. Since net profit is the sum of the contributions from all divisions less corporate interest, income taxes and corporate overhead, the net contribution of each division is difficult to separate because of the complex allocations that are carried out to obtain the overall corporate results. The gross contribution to corporate profitability per barrel of product produced (as shown in the companies' reports) were calculated and are subsequentially presented graphically.

Figure 8-7 shows the weighted average refining and marketing profit, dollars per barrel (before interest, income taxes and corporate overhead) for the six very large integrated international oil companies("Six Sisters":BP, Chevron, Exxon, Mobil, Shell and Texaco) for their operations in the United States for the first quarter 1989 through the second quarter 1992. The maximum and minimum profitabilities of the six companies are also shown. Similar data is depicted for their operations outside of the United States in Figure 8-8.

Figure 8-7



BEST AVAILABLE COPY

104

Figure 8-8

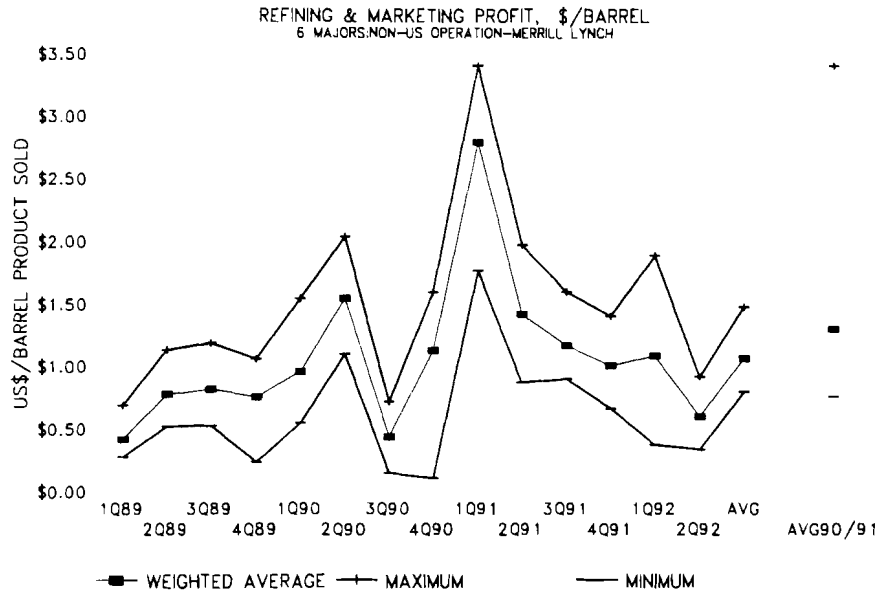
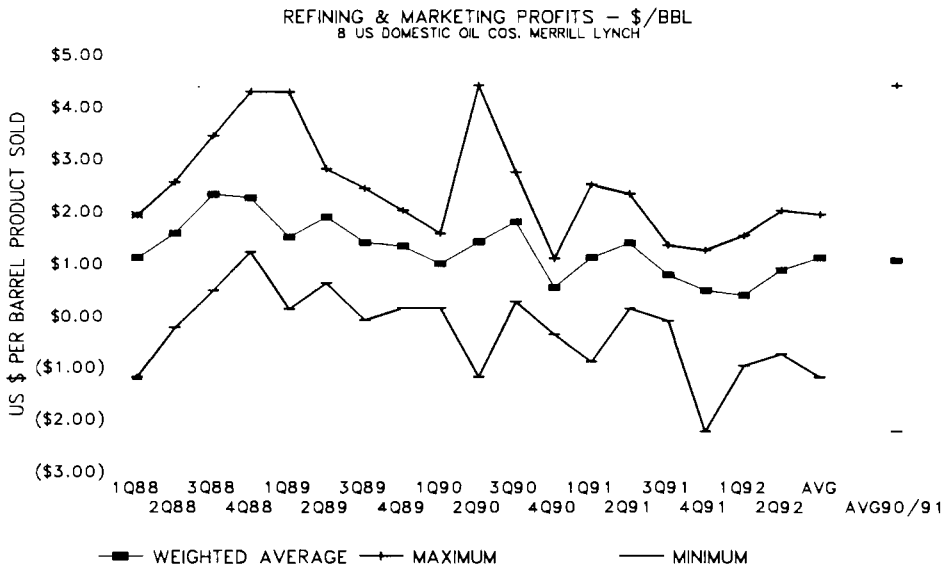


Figure 8-9 presents the same data for eight US independent oil companies (Amerada Hess, Amoco, Atlantic Richfield, Kerr-McGee, Phillips, Sun, Marathon, and Unocal) for first quarter 1988 through second quarter 1992.

BEST AVAILABLE COPY

105

Figure 8-9



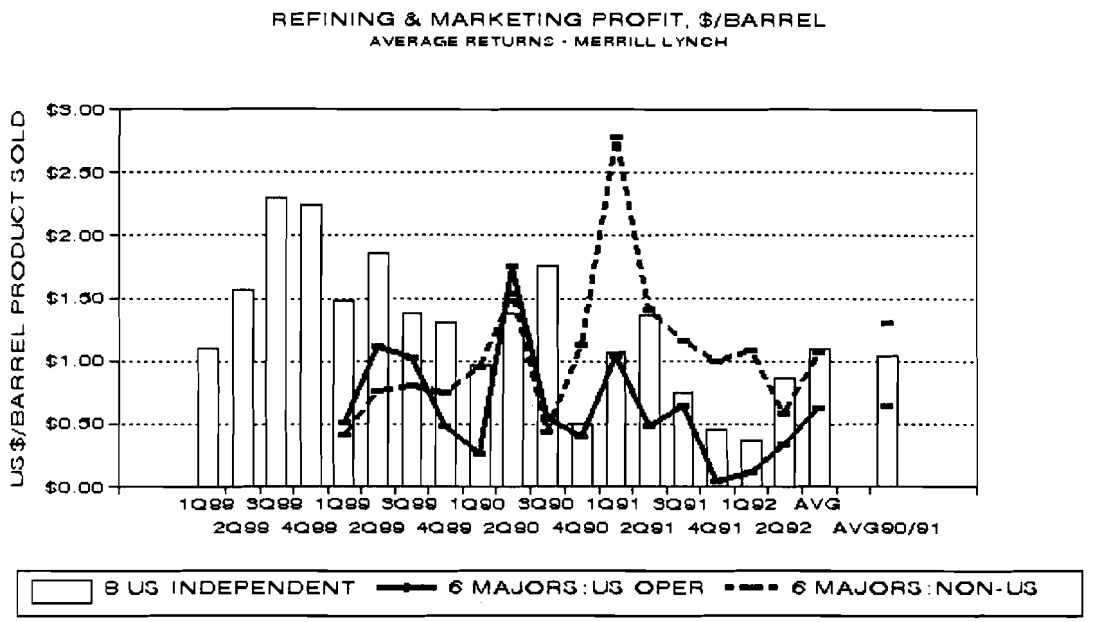
The maximum, minimum, and average profitabilities are shown in Table 8-7. Again it should be noted that profitabilities are earnings before interest and taxes (EBIT) and other corporate overhead. The average profitability of each of these three groups by quarters are displayed in Figure 8-10 for ease of comparison.

Table 8-7

Refining and Marketing Profitability

	Six Sisters		
	US	Non-US	Eight Independents
Profitability	US$/ Barrel	US$/ Barrel	US$/ Barrel
Maximum 1989-1991	0.89	1.42	1.92
Average 1989-1991	0.63	1.06	1.10
Minimum 1989-1991	0.19	0.79	-1.20
Average 1990-1991	0.65	1.30	1.03

Figure 8-10



It should be noted that the refineries of the mentioned companies are generally very complex with high conversion capabilities. The gross margins (product value less crude cost) generated from these refineries are larger than those generated from less complex and less expensive refineries. The reported profitability also includes profits derived from diverse associated activities such as: convenience stores, car wash and lube retail facilities, and other retail profits.

Data were also developed on refiners' gross margins based on processing specific crudes through generic refineries in Singapore, Rotterdam and the US Gulf and West coasts. This is shown in Figure 8-11. The gross margins by months from January 1987 through October 1992 are shown based on three month rolling averages of cargo product prices and crude prices. No allowance was made for refinery operating expenses. These are GROSS margins, i.e. cargo product value less crude costs. The average for the six year period 1987-1992 and for the two year period 1990-92 are shown in Table 8-8.

Figure 8-11

REFINERY GROSS MARGINS

PRODUCT VALUE LESS CRUDE: MERRILL LYNCH

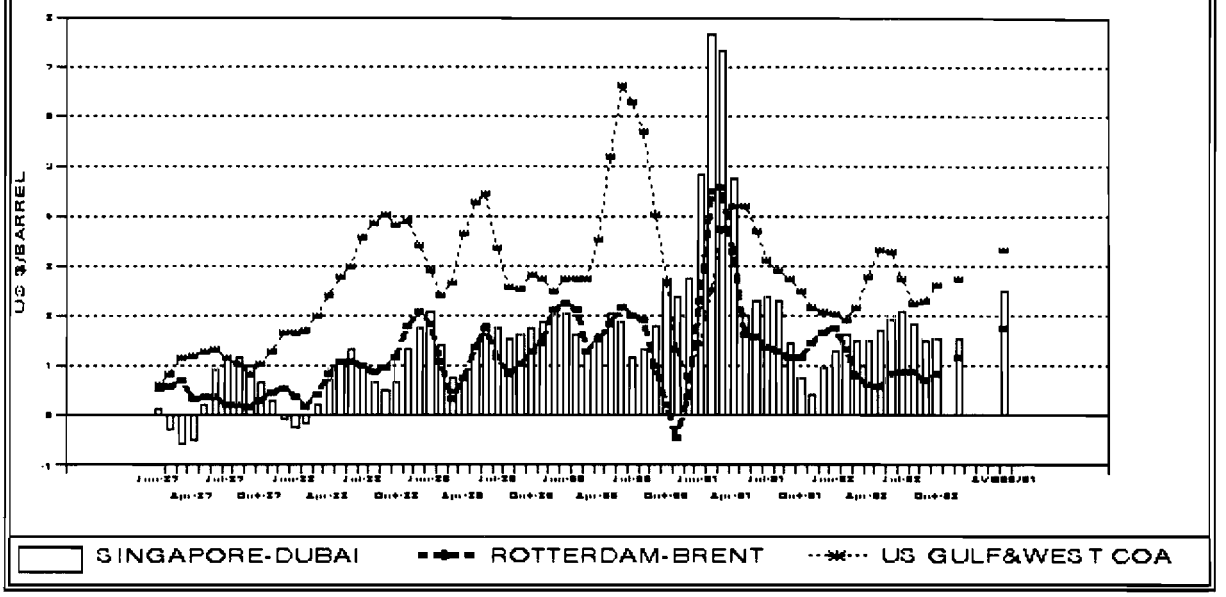


Table 8-8

Gross Margins

	1987-92	1990-91
Singapore processing Dubai crude	1.54	2.48
Rotterdam processing Brent crude	1.19	1.78
US Gulf & West Coast processing West Texas Sour and Intermediate and Alaska North Slope	2.75	3.34

The higher gross margins for the US refineries are a consequence of their much greater complexity and conversion capabilities than those applicable to Singapore and Rotterdam refineries.

The Oil & Gas Journal publishes "Wright Killen Refining Margins" on a monthly basis. These margins are the Wright Killen & Company's estimate of the average cash margin realized by US Gulf coast refiners when all products are sold into the wholesale market. The published data are based on average wholesale (terminal, not cargo as used in the previous data) product prices, average costs of crude processed, and average product yields produced by these refineries. Estimates of cash

BEST AVAILABLE COPY

108

operating expenses (July 1992 = 2.67 US$/bbl) and feedstock costs were deducted from the aggregate product value to obtain the cash operating margin. No depreciation, income taxes, interest, or other financial charges were included.

The complete history of the Wright Killen Refining Margins is portrayed in Figure 8-12 with the margins presented on a rolling three month basis to dampen timing effects of crude and product pricing. The results are summarized in Table 8-9.

Figure 8-12

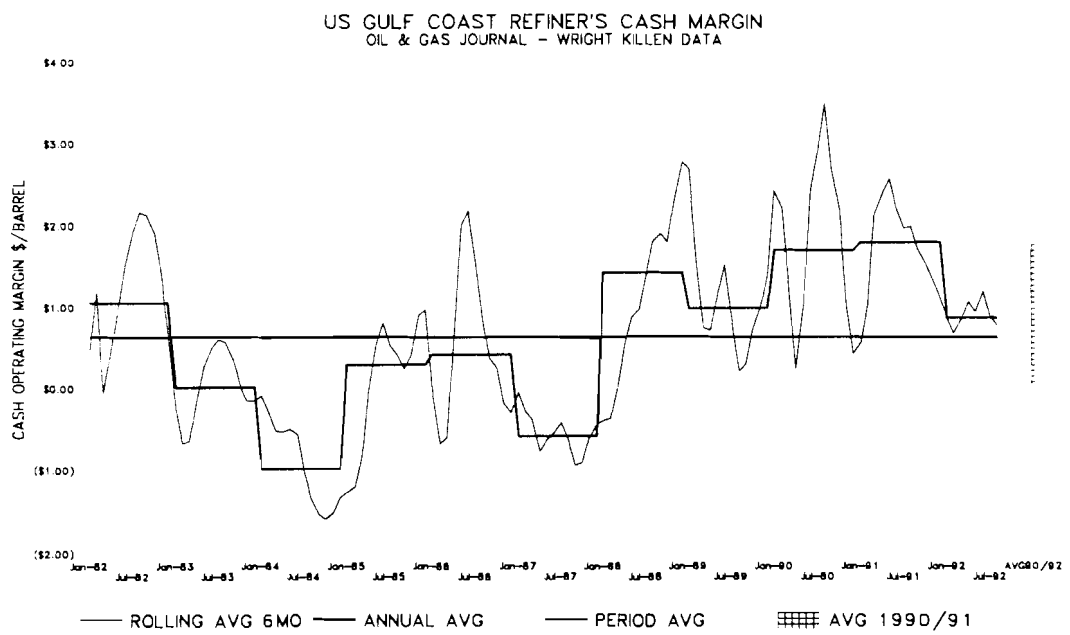


Table 8-9

Wright Killen Refining Margins Summary

	US$/Barrel
Average 11 years (Jan 82-Jan 92)	0.63
Maximum Annual Average	2.02
Minimum Annual Average	-0.99
Maximum monthly margin (absolute)	4.21
Minimum monthly margin (absolute)	-2.18
Maximum 3 month rolling	3.49
Minimum 3 month rolling	-1.60
Average for 1990-91	1.78

BEST AVAILABLE COPY

These data reflect the wide swings in margins experienced by the refining industry. While the average margin over the eleven year period was a modest 0.63 US$/bbl, the swings between maximum and minimum margins were 3.01 US$/bbl on an annual basis, 6.39 US$/bbl in absolute terms and 5.09 US$/bbl on the more representative three month rolling average.

Similar, but more volatile swings can be noted in the gross margins based on cargo prices as presented in Figure 8-11 and noted previously. There appears to be no obvious reason to anticipate any reduction in the volatility of the refiners' margins in the future.

8.3.3 Comparison of Philippine Companies' Returns with Others'

Table 8-10 summarizes the comparison of the Philippine Companies pro forma with the data described in the previous section.

The data for the Philippine refineries include marketing expenses and freight underrecovery totalling 1.37 US$/bbl. Products sold at terminals in relatively small lots should command a differential over cargo prices to recover the additional expenses incurred as well as some profit. The Philippine sales are at the terminals while those for the other refiners are based on cargo sales with no marketing or product transportation expenses. A more meaningful comparison of the Gross Margins on an adjusted basis is to take into consideration the marketing and transportation expenses are shown in Table 8-10. The figures include a markup of 1.37 US$/bbl which effectively assumes no additional profit going from refinery gate sales to marketing sales but does assume recovery of additional expenses.

Table 8-10
Margin Comparison
1990-91

	US$/Barrel	
	Base	Adjusted
Philippine Refineries	2.15	2.15
Singapore Refinery	2.48	3.85
Rotterdam Refinery	1.78	3.15
US Gulf/West Coast Refinery	3.34	4.71

Even these adjusted margins need further examination. The Philippine refineries have an average Complexity of 3.1 (Complexity is an industry accepted index of the amount of process facilities downstream of the crude unit which upgrade the value of the production). The Singapore and Rotterdam refineries have complexities of 6 to 7 while the US refineries have complexities approaching 10. The higher the complexity, the higher the investment and operating expenses and the higher the margin realized when processing a given crude slate.

A comparison can also be made to the Wright Killen data presented in Figure 8-12. The net margins in the period 1990-91 are based on terminal prices from which operating expenses have been deducted. For the 1990-91 the net margins (in US$/bbl) compare as follows:

(a) Philippine refineries 0.55 US$/bbl
(b) US Gulf Coast average refinery 1.78 US$/bbl

Again, one should expect a higher margin from the US Gulf Coast refineries because of their higher complexity, conversion, and upgrading capability. This result should be partially offset by the fact that the marketing expenses are included in the data for the Philippine companies, whereas the US data includes expenses only up to the terminals.

8.4 Summary And Recommendations

Refining and marketing divisions (R&M) of integrated oil companies generally produce lower profitability and returns than the exploration and production (E&P) and other segments of the industry. Direct explicit comparisons of the financial performance of the Philippine refining and marketing companies with that of similar companies in other countries are not possible due to the unavailability of specific data on R&M companies or divisions required for such a comparison. However, several benchmarks were developed so that the general comparisons are possible and an overall assessment can be made.

Comparisons of return on sales, assets and equity for the Philippine companies with that of six integrated international companies and eight US domestic companies are presented below:

Table 8-11

	Rates of Return, 1987-1991		
Companies	Sales	Assets	Equity
Caltex	2.0	3.5	21.1
Petron	3.2	4.6	23.0
Shell	3.4	4.6	14.5
Philippine Industry	2.9	4.3	18.7
Six Internationals	4.6	5.4	11.8
Eight US Independents	5.0	4.8	15.5

Return on sales is distorted in all cases since sales revenue includes taxes which is passed on to the governments. However, the revenue for the six internationals and the eight US domestics include a large portion of sales as crude oil, chemicals and other sales which generally have a higher markup over cost and lower tax

BEST AVAILABLE COPY

burden than refined products. Therefore, it should be expected that percent return on sales would be lower for companies with only returning oil marketing divisions.

Return on assets are greater for the six internationals and the eight US domestics than that realized by the Philippine companies. Again, E&P, chemicals and other segments of the industry have historically generated more attractive returns than have the R&M sectors. However, a rate of return of 4.3%, as experienced by the Philippine companies over the five year period, is inadequate to generate the required cash flow to sustain, much less expand, an efficient, viable operation.

Return on equity was greater for the Philippine companies than that for either of the other two groups. Return on equity is highly influenced by debt policy or requirements. Leverage increases return but is accompanied with increased risk.

ERB granted price increases of 0.12 peso/liter in October 1992. This amount of increased revenue (after 35% income tax) will increase the return on sales by 1.1%, return on assets by 2.0% and return on equity by 8.5%. Had this increase been in effect for all of 1991, the return on assets would have been 8.4% for the Philippine R&M industry.

Extensive data were presented depicting margins of Philippine, US Gulf/West coast, Singapore, and Rotterdam refineries. Additional data was presented on US Gulf Coast refinery profitability over an eleven year period. While the data is not exactly comparable due to the different types of markets, varying complexities of the refineries, etc, some insights were observed. Refining margins are highly volatile throughout the world. Considering the relatively low complexity of the Philippine refineries and the differences in the markets, the margin realized is not greatly out of line with that of refineries in other locations.

In summary, refining and marketing investments have generated only marginally attractive returns. The experience of the Philippine companies have been in line, but slightly lower than that of the other countries' refineries for which data were available. The returns realized by the Philippine have not been adequate to fully justify additional investments. With the 0.12 peso/liter price increase granted in October should increase return on equity to 8-9%. Another increase of similar size should increase returns to 10-11% which would make additional investments more acceptable to shareholders.

9 DISTRIBUTION AND DEALER MARGINS - FUTURES USE IN SETTING PRICES

This chapter discusses several relevant topics, namely:

- Distribution facilities and their related transportation
- ERB role in setting tariffs for the distribution process
- Recovery of distribution costs
- Possibilities of price stabilization through the use of futures

9.1 Product Distribution

The products produced by the refineries and those imported are distributed through a total of 85 terminals and bulk plants throughout the islands. The principal means of transporting the product to the terminals are: (i) marine transportation, and (ii) a pipeline complex from the Caltex and Shell refineries in Batangas to Manila.

Over 42 inter-island services tankers with capacity totalling 836 thousand barrels and 27 barges with capacity totalling 163 thousand barrels are utilized in moving product to the terminals.

9.2 Distribution and Transportation Pricing

The ERB sets the rates that are to be added to the refinery gate permitted prices to arrive to the prices of the products delivered at the terminals. The ERB sets specific rates for both the white and black oil products delivered to each terminal of the distribution system.

ERB uses several methods and procedures to establish the transportation component of the distribution tariffs. These methods are summarized as follows:

- Marine transportation rates are based on the shipping costs actually incurred by the oil companies, as calculated from the invoices presented by third party individual shippers or shipowners.

  Reasonable shipping charges appear to result from real competition among individual shippers and shipowners. However there seems to be no real determination by ERB of the appropriateness of these charges since it is assumed that there is vigorous competition in the shipping segment. It appears that the competition is sufficient to result in fair pricing practices.

- The pipeline rates are set by the ERB pursuant to public hearings where the performance of the pipeline company is reviewed. The criterium to set rates is that a fair return on rate base will be obtained by the pipeline. Rate base is composed mainly of the net depreciated value of the pipeline assets, priced at replacement cost.

The determination of the fair return on rate base is a procedure widely used in countries where there is a regulatory tradition. This method is particularly adequate in situations where there is not a well-developed stock market [1].

9.3 Evaluation of ERB Authorized Distribution Rates

An analysis of the adequacy of the ERB authorized distribution rates (to the terminals) to cover actual costs follows. The revenue obtained by applying the rates set on August 12, 1991 and revised on April 14, 1992 to their respective deliveries of products to each of the terminals (for the first six months of 1992), are compared with the actual corresponding expenses reported by the three oil companies.

The data used in the calculations comprised information for each terminal. The following initial data were used:

- ERB Rates

  For White Oil and Black Oil - August 12, 1991
  For White Oil and Black Oil - April 14, 1992

- Reported Cost - First six months, 1992

  By: Caltex, Petron and Shell

- Actual Volume Shipped - First six Months, 1992

  By: Caltex, Petron and Shell

Tables IX-1, IX-2 and IX-3 in the Appendix show the calculations of over or under recovery of shipping costs based on the differences of actual cost less allowed rates for each of the two (1991 and 1992) ERB rate schedules, for Caltex, Petron, and Shell.

Figure 9-1 depicts the calculated revenue for each of the two ERB rate schedules and the cost based on the six months volume for each company. Actual costs for all companies exceeded the revenue derived from the August 1991 rates.

The April 1992 rates permitted Petron and Shell to slightly over recover their costs. However, Caltex did not recover its costs for the six month period. If the new rate schedules are adequately designed, it should be expected that any over recovery during the expected effective period of the new rate should produce sufficient revenue to compensate for previous under recoveries.

Figure 9-2 shows the difference between the allowed rates and the actual costs.

---

[1] Other widely accepted methods to calculate return are: (i) Return on equity (the return should be sufficient to attract investors from a well-organized security market), (ii) return on net assets calculated at original cost (does not take into account inflation nor devaluation of currencies, and (iii) marginal costing (which has the goal to achieve maximum economic efficiency by assuming that all prices are established in accordance with the corresponding marginal cost for the goods or services being provided).

Figure 9-1

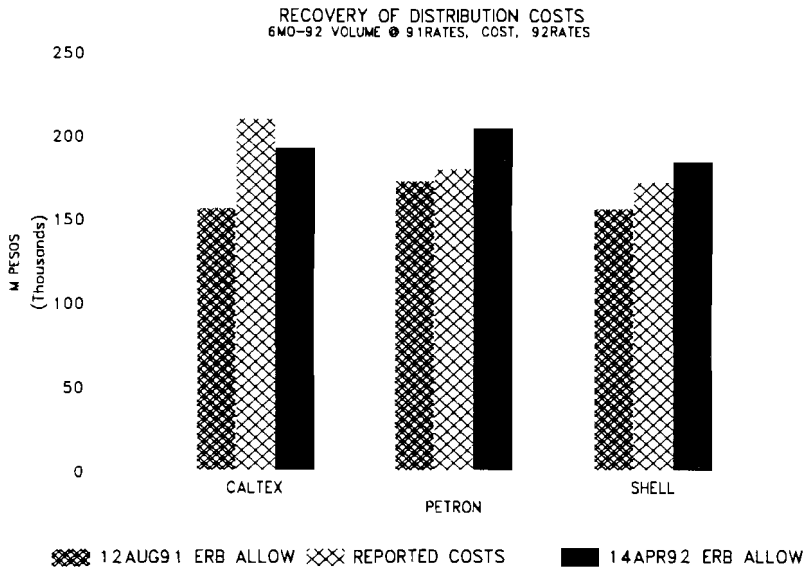


Figure 9-2

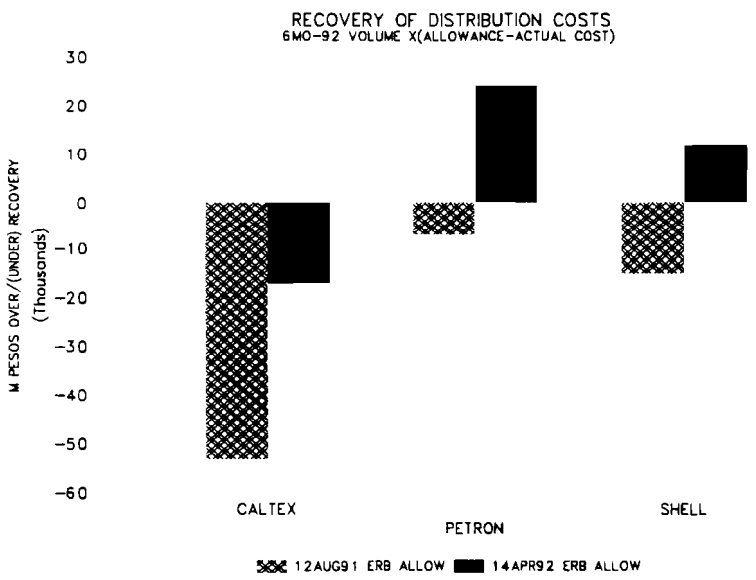
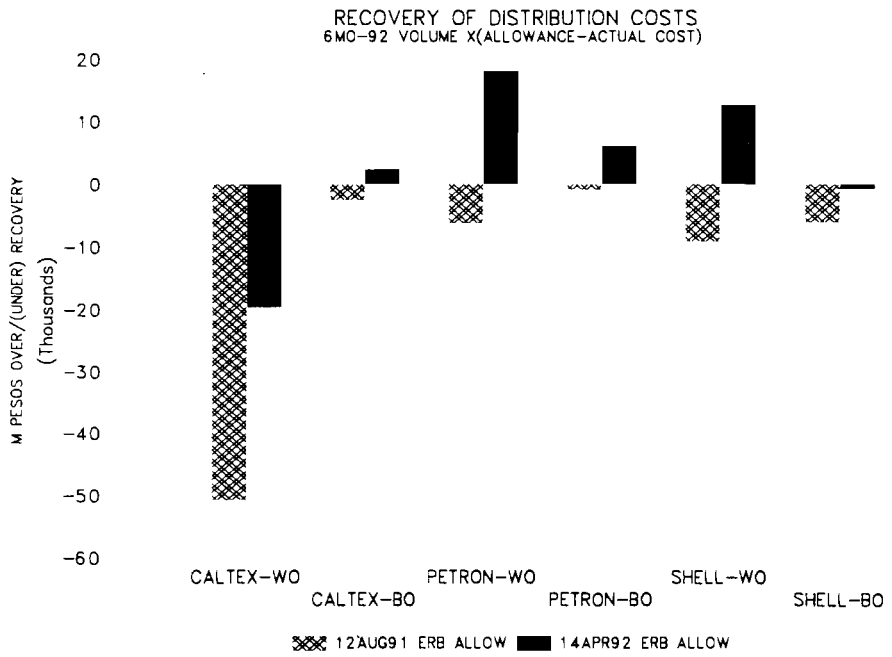


Figure 9-3 shows data from Figure 9-2 segmented between white oil and black oil products. It can be noted that Petron and Shell over recovered from white oil while Caltex under

Figure 9-3



recovered under the April 1992 ERB rates. Caltex and Petron over recovered for black oil but Shell slightly under recovered. Figure 9-4 presents the same data on a Peso per liter basis.

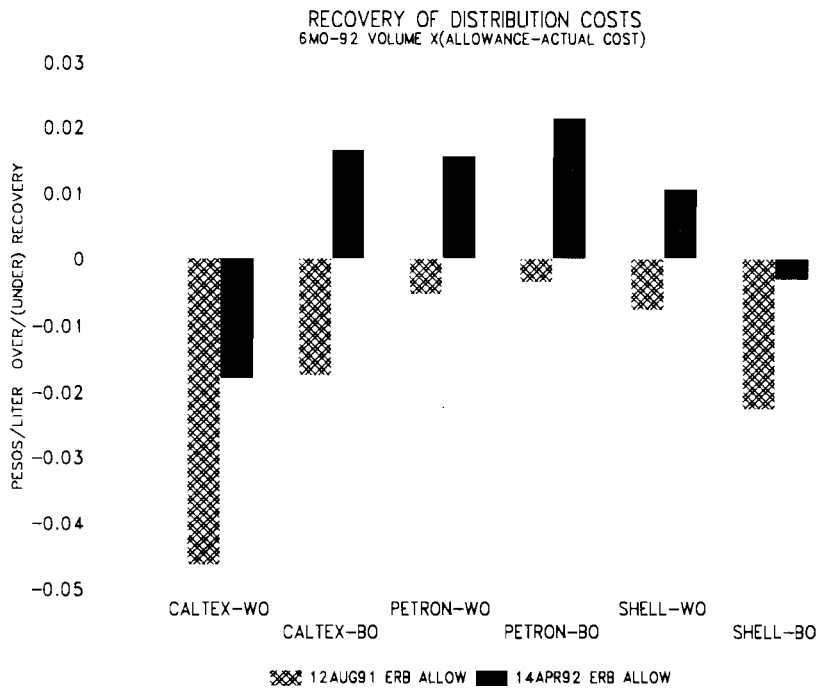
Globally, the existing rate structures appear to provide a pricing structure that is adequate for the existing conditions, assuming that shipping cost levels do really reflect a situation of open competition. However, some adjustments may be required between white and black products.

9.4 Dealer Margins

The authorized Pump Price for products differ from region to region, and include the dealer markup. For example, the Metro Manila area for certain products set by ERB is the sum of wholesale posted price plus hauling charge plus dealer mark-up. Table 9-1 shows the ERB reported dealer mark-up for specific products, as of October 14, 1992.

A description of the specific procedure used by ERB for arriving at the appropriate margin or markup for each product for each region was not available from ERB or DOE. It is understood that data available from the dealers for ERB's use was limited and inconsistent. It was further understood that the limited data available was reviewed by ERB and used to establish authorized margins for the dealers. Although the data available was limited it appears that ERB analyzed the data and established reasonably appropriate margins based on K&M's review.

Figure 9-4



DOE furnished financial data for six stations covering one to three years of operation. The data for these six stations covered only a total of ten specific station years of operation. Volume data was available for only seven of these years. All data was from service stations in the Metro manila area.

From the seven data points available it was determined that the average cost of service station operation equated to 0.3165 pesos per liter of product sold. Five of the data points are for 1990 operations and the remaining two are for 1989.

While the data is extremely limited it would appear that the margins of from 0.4307 to 0.4748 peso/liter set for metro Manila as shown in Table 9-1 give some profit to the dealers. Sufficient data was not available to determine if that level of profit is adequate. The data available is

Table 9-1
Dealer Markup
Metro Manila Area

	Dealer Markup Pesos/ Liter
Premium Gasoline	0.4748
Regular Gasoline	0.4554
Kerosene	0.4307
Diesel	0.4504

over two years old and costs have likely increased with inflation. More extensive data points from more recent operations should be used in establishing appropriate margins.

ERB has noted that applications for additional stations exceed the number of dealers withdrawing from operations which would seem to indicate that the margins permitted by ERB are attractive enough to prospective dealers.

Cost of US dealer operations generally range from 5 to 7 cents per gallon as compared to the 0.3165 pesos per liter average as indicated from the limited data for the Philippines (about 5 cents per gallon at 25 pesos/US$). However, a direct comparison of US and Philippine dealer costs are not too meaningful due to the different type of operations and the different cost structure.

Regardless of whether price regulation of dealer markups is to continue or not in the near future, there is ample justification for ERB to direct a thorough study to determine the cost of dealer operations including: (i) the elements of these costs, (ii) investment requirements, and (iii) methods used to track current costs. Included should be the development of specific methods to apply indexing and escalation factors, so as to assure fair returns to the dealers. Consideration should be given to the effect on dealers' revenues of auxiliary sales of non-fuel items.

9.5 Use of Futures Markets to Stabilize Prices

9.5.1 The Commodity Markets Mechanisms

Many commodity producers and consumers utilize the commodities exchange markets to lock in an acceptable price for the sale or purchase of their commodity at some specific time in the future. The buyer must realize that if the locked-in price (the futures price of the commodities) is lower than the corresponding market price at the specified time of delivery, then the cost would be less through the use of the futures market. Conversely, if the then current price is lower than the futures contract, then the futures contract would have been more costly than buying at current market price. The buyer must be willing to accept either possibility since the buyer had decided that the futures price contracted was acceptable based on the judgement at the time of execution.

In addition to the actual producers and consumers who hedge their sales or purchases as described in the preceding paragraph, speculators utilize the commodity exchanges as a vehicle to take risk positions in the expectation that whatever position taken in commodity contracts can be reversed at a later date for a profit. Unlike the hedger, the speculator has no real interest in the physical delivery of the contracted commodity. In most cases even the hedger reverses the futures position and utilizes the gain or loss in covering the commodity requirements and, thus, has adjusted the actual net costs (in the case of the buyer) or the net sales realization (in the case of the seller).

9.5.2 The New York Mercantile Exchange (NYMEX)

Petroleum futures began trading on the NYMEX in 1980 with the introduction of the No. 2 Fuel Oil contract. Gasoline and crude oil followed shortly

thereafter. The NYMEX has been very successful with volume growing to over 60,000 contracts a day for crude oil alone. These contracts represent 60,000,000 barrels of crude since each contract calls for delivery of 1,000 barrels of crude oil. This is equivalent to about the total daily world crude oil production. The actual deliveries amount to less than 3% of the contracted volumes since most positions are reversed prior to termination, as explained in the previous paragraph.

The cost of buying and selling a contract can vary from as low as around US$ 10 to as high as US$ 50, depending on the amount of business conducted by the customer. In addition, a deposit of from US$ 500 to US$ 2,000 is required per contract. Moreover, the owner of the contract is subject to margin calls, so as to make sure that the owner will preform on the contract if the market moves away from the contract position. For example, if a contract were made in December to purchase 1,000 barrels of West Texas Intermediate crude the following June at US$ 20 per barrel and the cash market were to drop to, say, US$ 15 in February, the owner of the contract would be required to make an additional deposit of US$ 5,000 (i.e US$ (20-15) = 5 times 1,000 barrels). (With Philippine total annual crude requirements in excess of 80,000,000 barrels, the exposure to margin calls would be overwhelming).

Many more commodity exchanges now deal in oil futures, but the NYMEX is still the prevalent one.

9.6 Use of Futures to Establish Product Prices in the Philippines

It has been suggested that crude futures be used by the ERB to establish future petroleum product prices in the Philippines. By use of such a procedure the crude prices for some specific time in the future could be locked-in. Since the crude price is the dominant cost element of product pricing (accounting for over 90% of the variable costs) then the product prices for that specific time could be forecasted with very good accuracy. This discussion is based on a scenario whereby the product prices would continue to be controlled through the ERB cost pass through mechanism.

The use of futures prices would have the advantage of knowing reasonably well the price levels of petroleum products at some specific times in the future. It would permit ERB to administer the OPSF with a greater degree of control and keep its balance within desired guidelines. It would also permit minimizing the frequency of price changes. It could result in lower or higher prices to the consumer. It would certainly result in greater public outcry and objections during those times when the then current crude prices are less than the future prices on which the product prices were based.

Dealing in crude oil futures requires a very sophisticated and experienced approach. Many long experienced crude traders, in large and small oil companies as well as in trading companies, have been caught in futures positions that were planned to be hedges but turned out to be high risk, losing positions. Literally hundreds of millions of dollars have been lost through taking positions without realizing the risks involved. For example, Showa Shell (Japan) announced in February, 1993 that it had incurred losses in petroleum futures exceeding US$ 1 billion.

Several questions must be raised and decisions reached if futures prices were to be used as a tool to stabilize prices in the Philippines. Some of the questions to be answered are:

- What futures would be used to establish the price base? Contracts can be purchased for one to eighteen months (or longer) in the future. Which time frame would be the optimum? Once decided would it be automatic, firm and consistent, or would some judgement go into when to use, for instance, 12 months versus some other number of months? What organization would make such a judgement, ERB, DOE, the oil companies or others? Would experience in crude purchasing be a selection criteria?

- Would futures contracts actually be executed or would the futures pricing be used only to establish future product prices? If used only for establishing product prices, would the oil companies be left to reach their own decision as to whether it would be best to hedge against a "known" product price slate in the future? Would Petron, as a public corporation, be treated differently than Caltex or Shell, each a subsidiary of international oil majors?

- Futures purchased at some time in the past for delivery in the then current month, will at times be significantly less or significantly greater than the then current spot or market price. If the current spot price were at, say, US$ 15 per barrel and the futures contracted twelve or six months earlier for current delivery were at, say, US$ 20, would the public and the government permit street pricing based on the higher US$ 20 when others in the region had prices reflecting the US$ 15 market price?

9.7 Use of Futures - Proforma 1987-1992

In order to present additional insight into the possible use of crude futures in establishing and stabilizing Philippine product prices, the history of spot crude prices and futures contracts since 1987 was analyzed. A six month and twelve month contract were arbitrarily chosen to be representative of the futures market.

Figure 9-5 presents monthly average data depicting: (i) spot prices for West Texas Intermediate, (ii) futures contracts for delivery in that same month when purchased six months prior to that month, and (iii) futures contract for delivery in that same month when purchased twelve months prior to that month. The current spot is somewhat more volatile than the six month and twelve month futures. This is not unexpected since it is generally anticipated that any large sudden move in either direction in the spot market will be moderated six to twelve months down the road.

Figure 9-6 portrays the difference between the futures purchased six and twelve months earlier and the current spot price. Any dramatic change in the spot market, up or down, is echoed in the futures market. For example, the large increase in spot crude prices in August 1990, due to the Iraq conflict, shows futures purchased six or twelve months earlier to be some US$ 16 - 17 less than spot. In contrast, the 6 months future peaked at US$ 10 above spot six months later and the twelve month futures was about US$ 8 higher than spot in August 1991. Clearly the futures bought earlier are lower, on average, than current spot. It could be surmised that there may be inherent pessimism in the oil industry, anticipating lower prices in the future. However, there can be no assurance that this phenomena will continue.

Figure 9-5

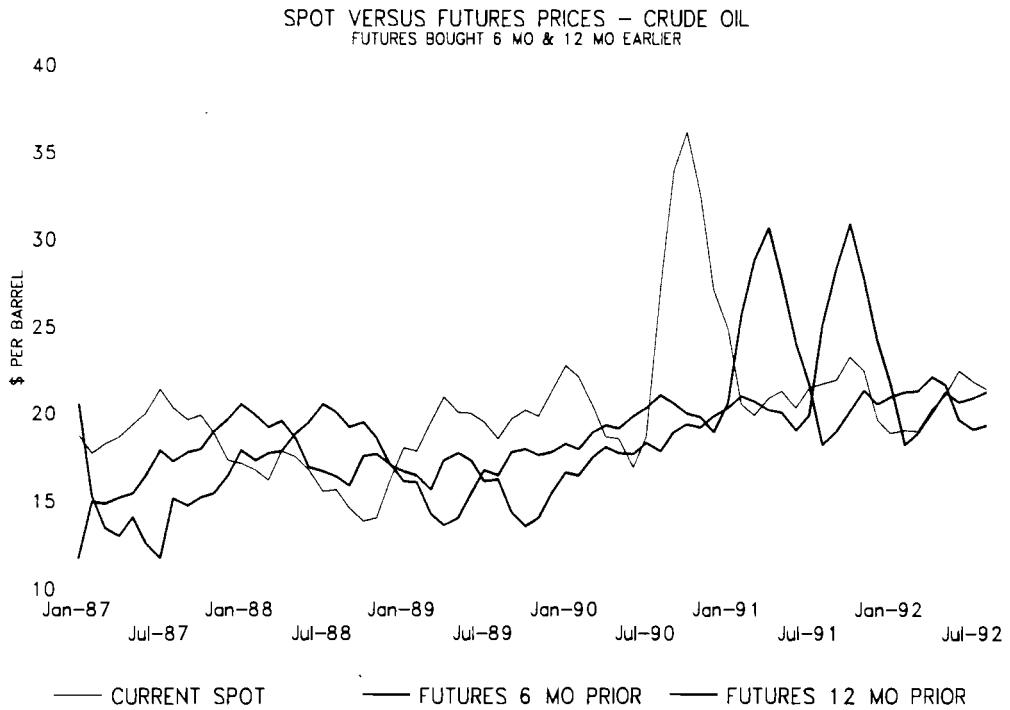
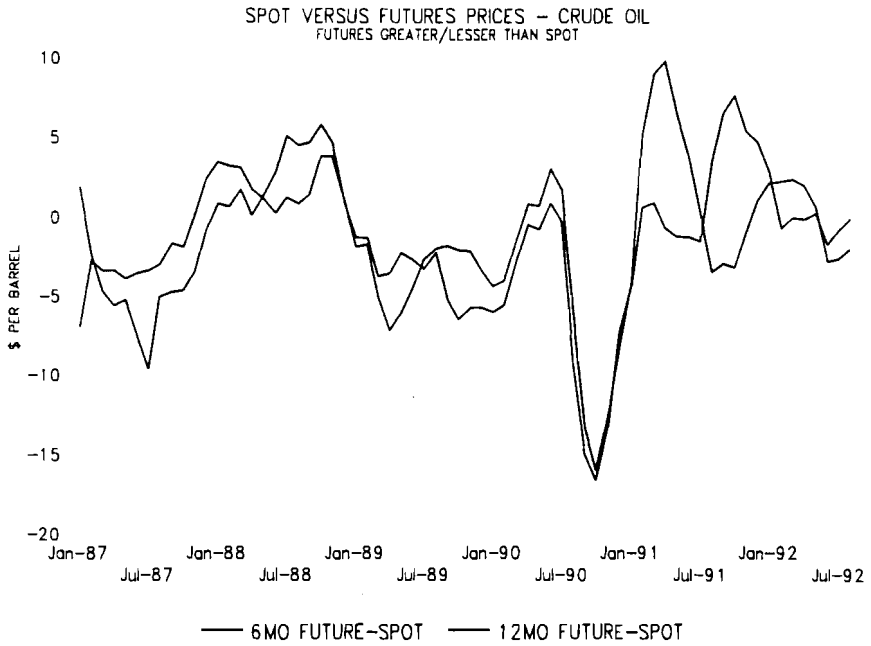


Figure 9-7 depicts the cumulative cost differential of purchasing 6 million barrels per month of crude through use of six and twelve months futures versus purchasing the same amount at spot. Savings would have been about US$ 530 million using six month futures and about US$ 740 million using twelve month futures for the 5 2/3 year period from January, 1987 through August 1992. However, the use of futures would have been US$ 160 and US$ 140 million more costly for six months and twelve months futures, respectively, for the 20 month period from January, 1991 through August, 1992.

As evidenced by these graphs, and with the advantage of hindsight, the Philippines would have had lower crude cost through rigid use of the six month or twelve month futures market over the previous six year period. Use of futures would have been more expensive over the 1991-92 period.

If it can be concluded from this historical evidence that <u>implementation of the use of futures</u> would result in lower costs than spot crude purchases, then perhaps futures should be used in setting Philippine product prices. It should be pointed out that, <u>if this were the case, speculators would have a sure winner</u> by buying futures and reversing their position as the contract comes to maturity, even if there is no necessity to have the commodity delivered.

Figure 9-6



9.8 Recommendations on the Question of Using Futures for Price Stabilization

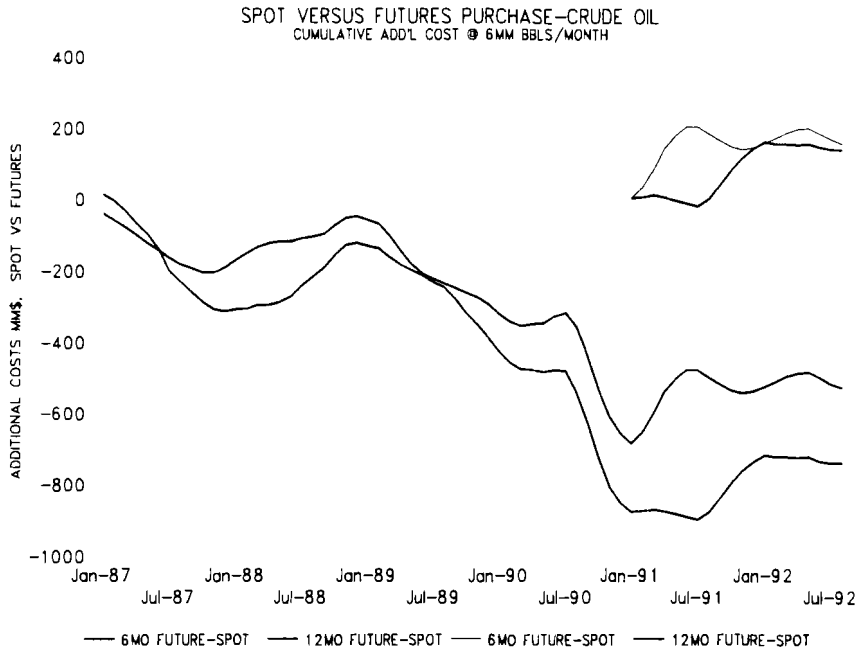
Use of futures would permit the forecasting of price levels with greater precision and would enable ERB to approve price changes and administer the OPSF in a more optimum manner.

The use of futures would not necessarily result in lower product prices. Covering all crude purchases with futures contract would result in additional costs to the Philippine economy. More importantly, use of futures is not without risk. Some of the factors that would increase the element of risk are: (i) inopportune timing, (ii) political or judgmental decisions to alter procedures to suit other requirements, (iii) no immediate availability of experienced personnel to administer the futures project, and (iv) the possibility that futures will generally be greater than spot prices over the longer term.

Consideration should also be given to the possibility of having to face public resentment and reaction when future prices are greater than market prices.

Since the disadvantages of utilizing futures to stabilize prices outweigh the perceived advantages, it is recommended that futures not be part of the ERB procedure to regulate petroleum product prices.

Figure 9-7



9.9 Summary and Recommendations

A review of the procedures used by ERB in setting transporting allowance based on marine and pipeline costs indicate the process to be adequate. A detail review of the adjustments granted by ERB in April 1992 for transportation allowances for both white and black were generally appropriate although some adjustments may be desirable between white and black products.

Procedures for setting dealer margins appear to be weak. The data available to ERB is lacking but it appears that the allowances granted are reasonably appropriate based on dealer applications and dealers withdrawals from the market. It is recommended that a detailed study be made of dealer costs, investment and returns be made so that ERB would have a better documented basis for setting appropriate margins.

Use of futures in setting controlled product prices was reviewed in some detail. Although such a procedure could result in future consumer prices being known well in advance, it is doubtful that either the public or the government would be willing to accept a situation if current prices, set in accord with futures mechanisms, were higher than those based on then current world market prices. It is recommended that futures not be used in establishing controlled prices.

10 OIL PRICE STABILIZATION

This chapter discusses the price volatility in the international oil market and reviews the past performance of the oil price stabilization program in the Philippines. The following issues dealing with oil price stabilization are addressed:

- Development of an automatic price regulating mechanism and whether it could assure that political motivations would not influence oil product pricing;
- The OPSF's role/success in achieving social policy goals in oil product pricing; and
- The impacts and effectiveness of the oil price stabilization program.

10.1 Oil Market Volatility

A plot of international crude prices from 1976 through 1991 is shown in Chapter 3, Figure 3-1, and the annual variation in price for each of the years is presented in Table 10-1.

In the 1970's, major price increases occurred in 1973 during the Arab Oil Embargo, and in 1978 - 79 during the Iranian Revolution. Oil supply surplus and the erosion of OPEC's control of crude oil pricing characterized the decade of the 1980's. Crude prices fluctuated considerably during the 1980's: dropping through 1981, 82 and 83, then leveling in 1984 and 1985 before the big drop in 1986. Since 1986, prices have been erratic, with the major spike being attributed to the Gulf War in 1990. For the years 1987, 88, 89 and 91, the average price variation was about 4 US$/bbl.

While the 1980's were a decade dominated by surplus oil supplies, during the 1990's that surplus is expected to diminish and increases in oil prices are likely to occur. Despite forecasters' tendencies to project price increases in terms of smooth growth rates, the actual occurrences of price increases are more likely to be in the form of price spikes, where the price at the end of the spike is not as low as the price at the beginning of the spike. Thus, price volatility is likely to continue, but it will be superimposed on an upward price trend.

10.2 Oil Price Stabilization in the Philippines - Review of OPSF

The OPSF was established in October, 1984 to minimize frequent changes in pump prices resulting from the volatile nature of crude oil prices and the peso-dollar exchange rate. The concept of the OPSF was to create a buffer fund. During a one-year period, crude prices fluctuate above and below an average price; product prices are set at an anticipated average price, then oil companies pay into the OPSF when crude prices are below that average and draw from the fund when crude prices are above that average. The problem is developing a good mechanism of setting product prices so that the concept works successfully in practice.

Table 10-1
Variation in Monthly Crude Prices During Year
(US$/bbl)

YEAR	AVERAGE PRICE	LOW PRICE	HIGH PRICE	HIGH-LOW
1974	12.44	9.49	13.06	3.57
1975	13.88	12.77	15.04	2.27
1976	13.37	13.26	13.71	0.45
1977	14.53	14.11	14.76	0.65
1978	14.46	14.40	14.94	0.54
1979	21.54	15.50	28.91	13.41
1980	33.97	30.75	35.63	4.88
1981	37.07	35.43	39.00	3.57
1982	33.59	32.78	35.54	2.76
1983	29.35	27.95	31.40	3.45
1984	28.87	28.02	29.26	1.24
1985	27.00	26.21	27.59	1.38
1986	14.31	10.91	24.92	14.01
1987	18.05	16.45	19.31	2.87
1988	14.71	12.54	16.10	3.56
1989	18.06	15.98	20.04	4.06
1990	22.20	15.15	32.88	17.73
1991	18.73	17.56	22.90	5.34

The OPSF is reviewed in this section by analyzing its success in minimizing the frequency of oil product price changes and examining the fiscal health of the fund. The OPSF's role in setting the relative prices of products is also discussed.

In Figures 5-1 and 5-2, the prices of gasoline and diesel in the Philippines are compared with the spot prices of the same products in Singapore. As shown in the figures, the controlled prices of gasoline and diesel in the Philippines were more stable than the Singapore market prices in 1986 and 1987. In April and August, 1988, Philippine prices were reduced while prices were also falling in the Singapore market; the OPSF balance was slowly building during this period (Figure 10-3). In November, 1988, the largest of the 1988 Philippine price reductions was made but, by this time, Singapore prices were again rising. Quickly the OPSF balance turned to a deficit, which continued to grow each month as the price of the major oil

products were held constant for a full year. In late 1989, an upward price adjustment was made which proved to be inadequate in rebuilding the OPSF, and the deficit was again growing in 1990 after only two months of OPSF growth. With the crude price increase that came with the Gulf War, the deficit reached nearly 17 billion pesos in November, 1990. Finally, in December, 1990, product prices were increased drastically and the deficit was erased.

The subsidy that had been provided to the purchasers of oil products in 1989 and 1990 was paid for by highly elevated prices in the 8-month period from December, 1990 to August, 1991. While most world buyers felt the distress of the Gulf War price spike for 2 - 3 months, for the Philippine oil product buyers, it lasted 8 months.

Figure 10-1

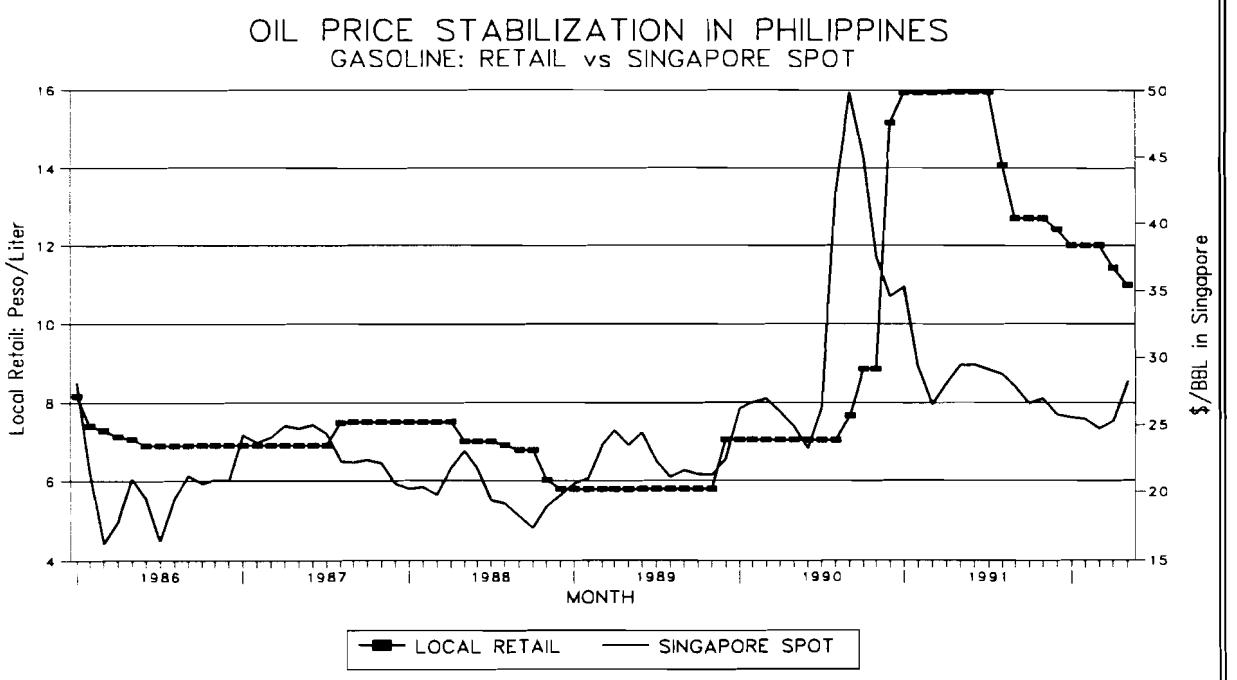


Figure 10-2

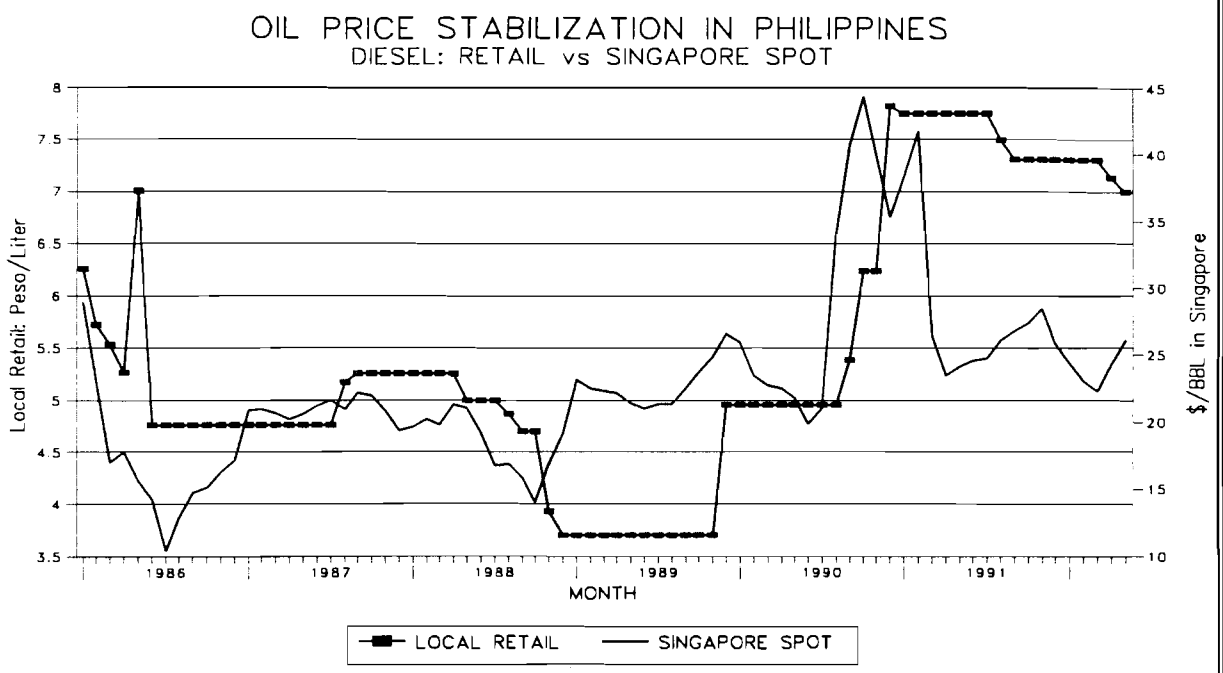
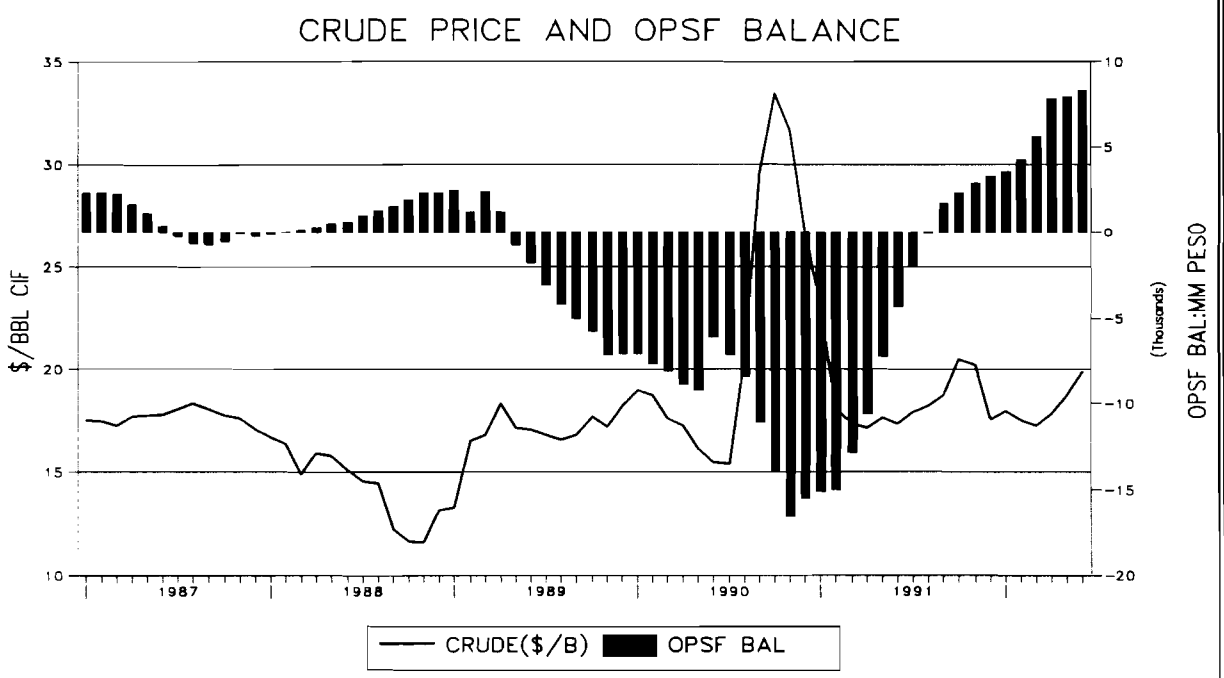


Figure 10-3



In the period from 1986 through 1991, the OPSF program simply changed the timing of payment and created some significant financial problems with deficits in the process. Ultimately, the prices dictated by world crude oil markets must be paid for by consumers through higher prices.

10.3 OPSF - Possible Automatic Price Adjustment Mechanisms

It has been suggested that the OPSF could be improved and the major problem, occurrence of large deficits, prevented with the creation of an automatic price change mechanism. Such a price change mechanism has been designed to evaluate its practical application, particularly concerning the following goals:

- Avoiding significant fund deficits;
- Incorporating social pricing goals in price changes;
- Minimizing the frequency of price changes.

The basic concept of the "automatic OPSF pricing mechanism" is to maintain the fund balance between a minimum and maximum level. Thus, as the fund balance approaches the minimum, oil product prices are increased, or as the fund approaches its maximum level, prices are decreased. Based on past experience and simulation of Philippine oil pricing with both historic pricing patterns and projected future prices, a price adjustment mechanism has been developed. The adjustment incorporates a number of concepts to achieve the desired goals.

First, the mechanism tries to anticipate reaching the pre-determined minimum and maximum and make changes before the limits on the fund range are exceeded. Even with an anticipation approach, a rapidly rising crude price can mean the minimum fund balance can be exceeded, particularly if the fund was in the lower part of the range when the price increase occurred.

Second, the mechanism also tries to tune the price correction to the recent changes in crude prices. If the crude price has been rising or falling rapidly and consequently the fund balance has also been changing rapidly, then a more drastic price change adjustment needs to be made to address the market situation. An acceleration term is used in the price adjustment mechanism to increase the level of correction and respond to a rapid rate of change in market conditions. Finally, the mechanism adds an extra increment or over-correction to the price adjustment to either rebuild the fund if it is approaching the minimum, or subtract an extra increment if the maximum has been approached.

Setting the various factors in the price adjustment calculation routine requires tuning to achieve a balance that best accommodates all of the goals. For example, if larger adjustments are made as the minimum balance is approached, then there is less chance of a deficit occurring; however, the price increase may be excessive and therefore publicly unpopular. In addition, the fund will rebuild more quickly and a price decrease may then have to be made sooner, which is contrary to the goal of minimizing the frequency of price change. Thus, an effort is made in setting the factors to achieve a "balance" in reaching the individual goals. Clearly there is a chance element: if a 5 US$/barrel crude price increase occurs when the fund is near the maximum level, then it can be handled, but if it occurs near the minimum, it is much more difficult to avoid exceeding the funds minimum and potentially incurring a deficit.

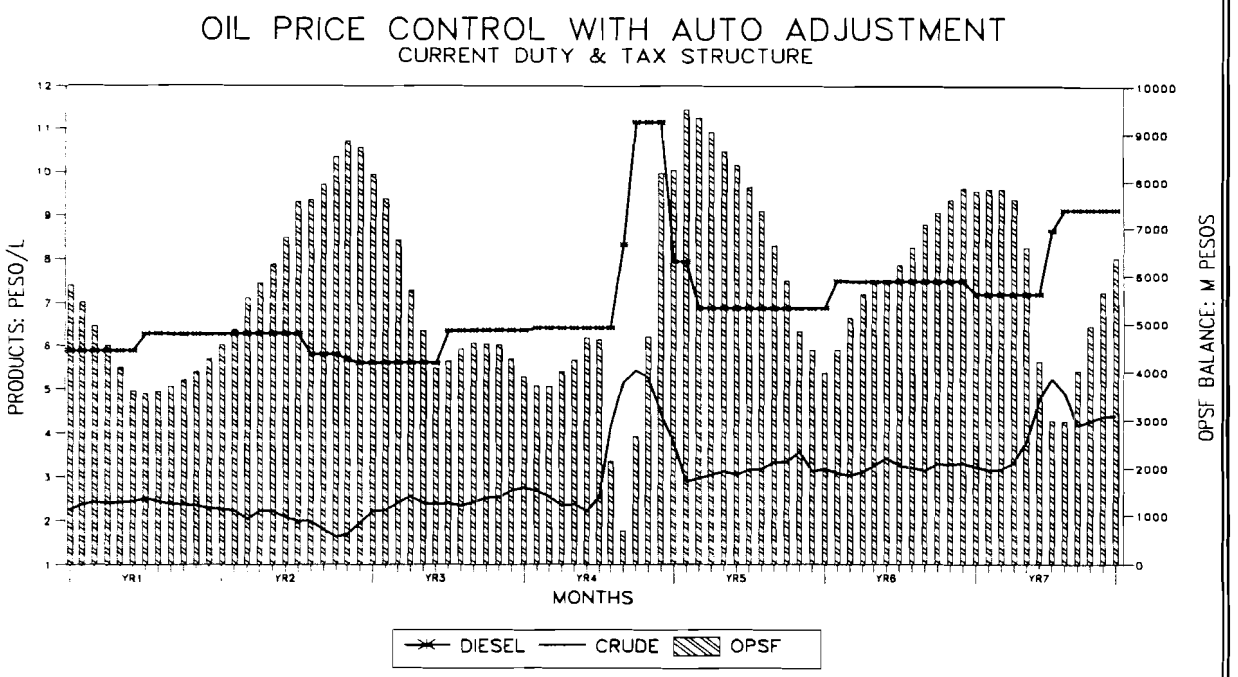
The variables in the OPSF Price Adjustment Model (OPSFADJM) are described in Table 10-3 (end of chapter) and the logic of the price adjustment calculation routines is described in Table 10-4 (end of chapter). An example of using this price adjustment mechanism is shown in Figure 10-4. The example covers a seven-year period; the first five years are based on the recent patterns of historical price change. The last two years show an additional price spike in which prices at the end of the spike are elevated above the real world prices at the starting point, which has historically been the pattern of price increases. The need for price change is examined each month, and an adjustment is made if necessary.

The type of price spike that occurred during the Gulf War is illustrated in year 4 of the example case and as shown, a crude price increase of 10 US$/bbl and accompanying foreign exchange impacts result in an OPSF drawdown of 2.5 billion peso in one month. Thus, to try to keep the fund within the target boundaries of 2.5 to 9 billion peso, the price adjustment mechanism must respond quickly, which it did with a price adjustment for the next month, followed by an additional increase the subsequent month to counter an additional market price increase. Even with this rapid response, the OPSF fell to 700 million peso.

During the seven-year sample period, there were 15 price changes, an average of 6 months between price changes. (Actual months before change were 6, 13, 3, 1, 7, 7, 7, 1, 3, 2, 11, 11, 6, 1, 6) The frequency of price change would have been less had it not been for the two price spikes, which can require rapid response to market price changes to avoid fiscal problems. In summary, when the crude market fluctuates within a modest price band, then frequency of price changes could approach one per year, but when the crude market experiences dramatic price fluctuations, then changes may need to be made more frequently. Ultimately, the market dictates the need for price changes.

Restating the first of the issues to be addressed in the this chapter, development of an automatic regulatory price change mechanism which would assure that political motivation would not influence oil product pricing, the example case demonstrates that indeed an automatic price change mechanism can be developed that would work in different types of market price environments. That, however, does not guarantee that it would function free of political influence. It is possible that the automatic price change mechanism could be overridden by someone who argues that their judgement is superior to the mechanism's formulae because of the "unforeseen nature of current market condition". And, in fact, it is true that there may be better price adjustment techniques than those of the automatic price adjustment model (OPSFADJM). The concern is whether a decision to override the OPSFADJM is based on improving the price change algorithm or is politically motivated. In conclusion, while developing an automatic price change mechanism will not necessarily guarantee that political motivation would not influence oil product pricing, it might, however, reduce the likelihood that such influences would enter the process.

Figure 10-4



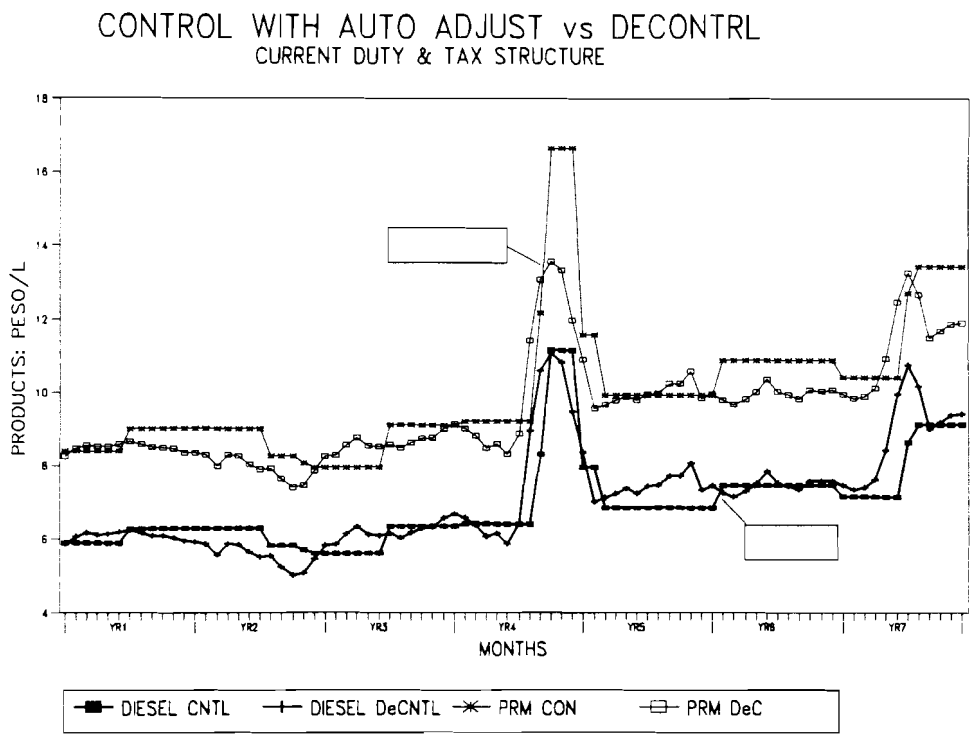
10.4 OPSF and Energy Policy Social Goals

In addition to its role in stabilizing oil product prices, OPSF has also played a role in setting prices to achieve energy policy social goals. The oil product pricing policy in the Philippines has been to make greater increases in the prices of "luxury products" (gasoline, avturbo, solvents) and lesser increases in LPG, kerosene, diesel and fuel oil as product prices rise.

In Figure 10-5, prices based on OPSF's historical pricing patterns are compared with decontrolled prices, assuming current duty and tax structure for both control and decontrol. The difference between the control and decontrol prices represents the OPSF element and results from two factors: i)the payments into OPSF which boost the average of all product prices or the subsidy from OPSF which lowers average prices; and ii)the cross-subsidization effect, which is shown in the figure as a higher price for premium gasoline and lower price for diesel controls. If OPSF were eliminated and the current duty and tax structure maintained, the control vs decontrol prices would not differ greatly with crude prices in the 17 US$/bbl price range, but at 25 US$/bbl crude prices, gasoline prices would be lower and diesel prices higher. OPSF's cross-subsidization of product prices can be seen as providing a mechanism for reshifting tax burden between products as prices rise and fall.

Thus, if historical OPSF product prices are accepted as reflecting the desired energy social goals, then the current duty and tax structure could be changed when oil product prices were decontrolled, eliminating the need for the OPSF as a means to obtain social goals. For the control and decontrol cases of Figures 5-6A and 5-6B, the crude duty and the 1.0 P/L special duty were both eliminated, and specific taxes

Figure 10-5



were placed on all products to generate the same total government revenue as received from the current duties and tax structure. During the seven-year period, the specific tax rates were changed only once, at the beginning of the fifth year. With the use of the specific taxes only, OPSF's primary function is controlling prices to achieve stabilization (i.e. reduced frequency of price change). As shown in Figures 5-6A and 5-6B, the controlled and decontrolled prices for gasoline and distillate are on average about the same; when OPSF is building, decontrolled prices are lower and when OPSF is drawing down, decontrolled prices are higher. The principal difference is that decontrolled prices are fluctuating with monthly variation in crude price.

With the current import crude duty, OPSF plays a useful role in redistributing the added duty cost as crude prices rise, especially when that rise is sharp. But, as discussed in Section 8, a duty on crude is less compatible with the Philippine energy policy objectives of pricing and government revenue generation, than the specific tax scheme of the above example. With the specific tax only, OPSF's frequency of price changes has been reduced and with either controlled or decontrolled prices, the swing from low to high prices is less (which should please

consumers), while the government revenue generation is approximately the same.

In summary, the average prices of premium gasoline and diesel over the seven year study period are compared in Table 10-2 below for control versus decontrol with i)the current duty and tax and ii)with the alternative specific taxes only.

Table 10-2
Average Premium Gasoline and Diesel Prices For Seven Year Period

	Current Duty & Taxes		Specific Taxes Only	
Avg. Product Prices (Pesos Per Liter)	Control	Decontrol	Control	Decontrol
Premium Gasoline	10.0	9.53	9.90	10.08
Diesel Fuel	6.93	7.08	6.86	6.82
Diesel Price/Prem. Gaso.	.693	.743	.693	.676

Figure 10-6A

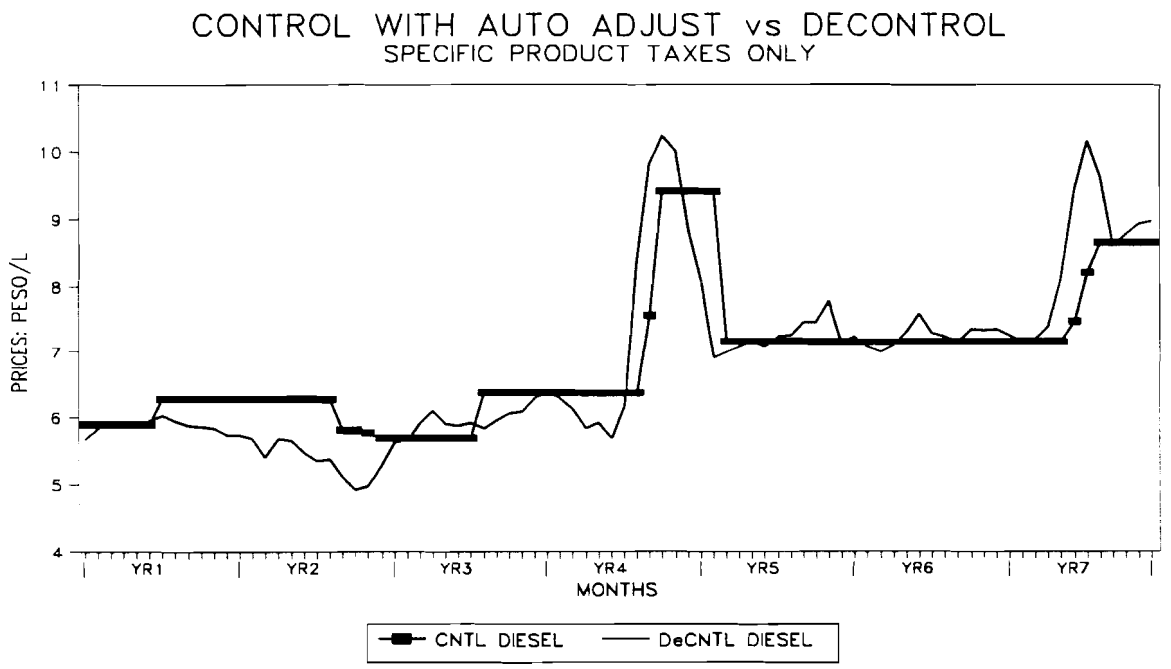
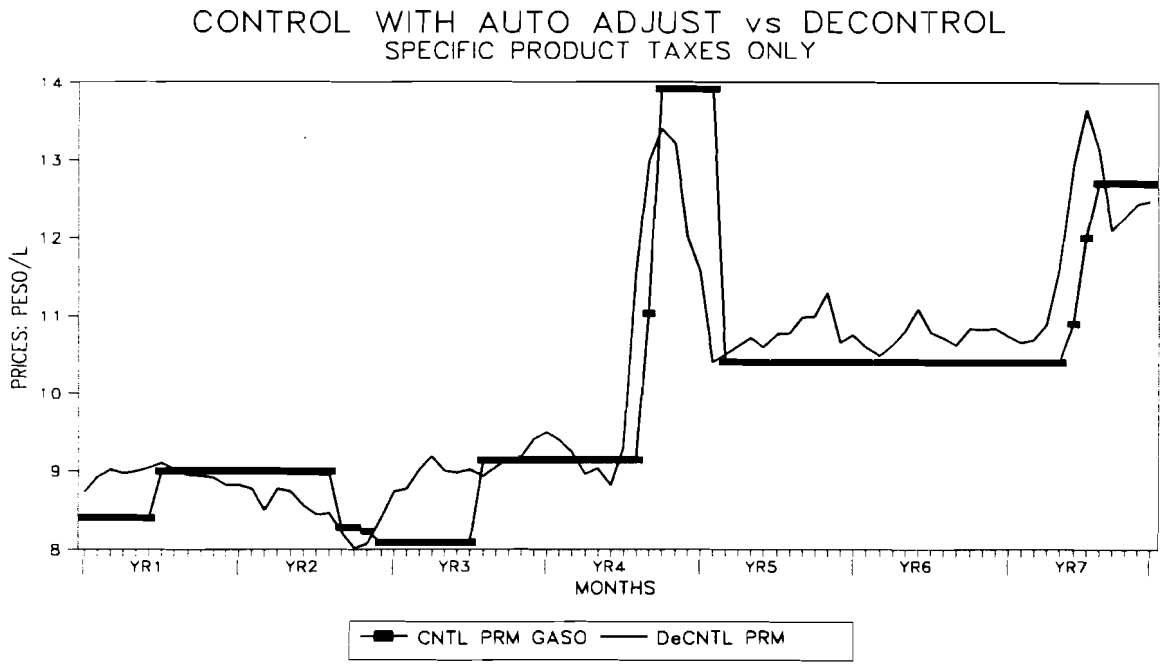


Figure 10-6B



The OPSF balance for the "Specific Taxes Only" case is shown in Figure 10-7. It can be seen that in this case, the balance goes into deficit for one month in year seven. This should not be taken as an indication that the automatic price adjustment mechanism performs less successfully with this alternative to the current tax and duty structure. It is an example of the "chance element" of a large price jump occurring at a time when the OPSF balance was near the low end of the range (after 27 months without a price change).

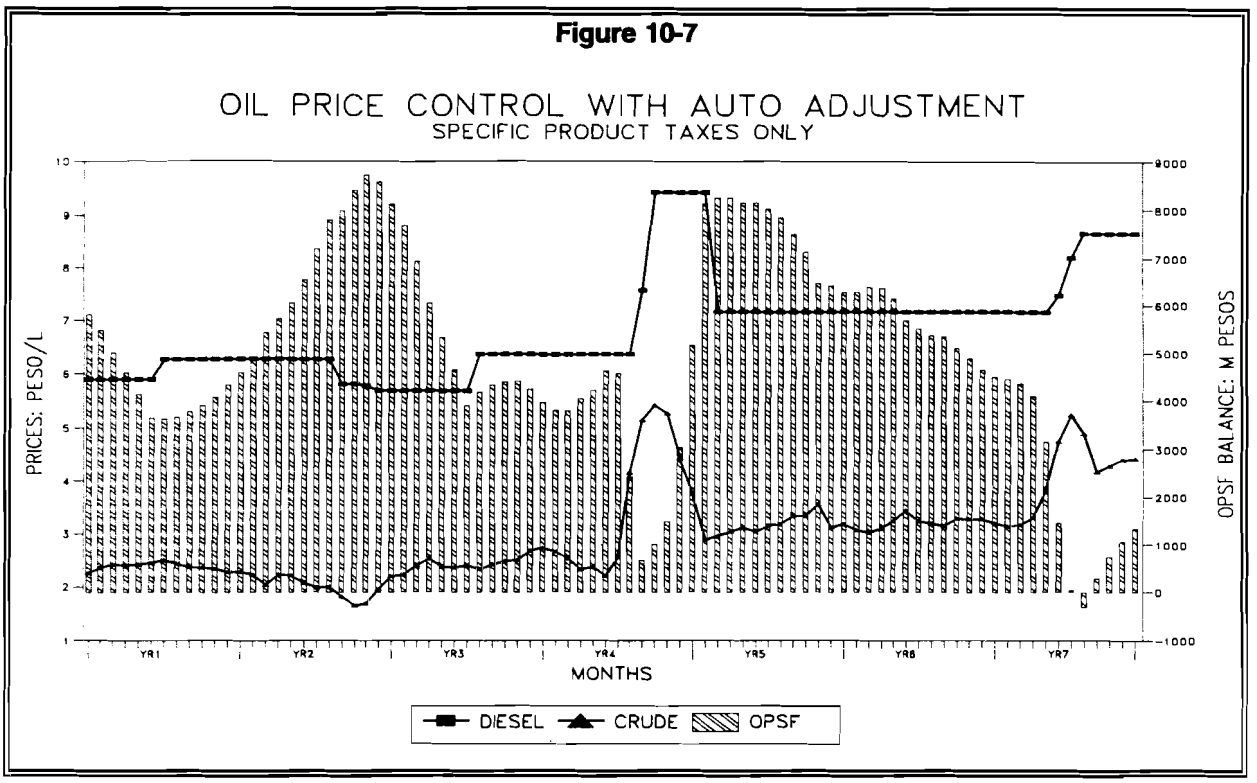
In summary, the same social pricing goals for oil products can be achieved without OPSF as with OPSF if the current tax and duty structure is changed.

10.5 Oil Price Stabilization - The Pros and Cons

The review of the previous sections has demonstrated that with OPSF, the frequency of oil product price changes can be reduced. It has also been seen that, historically, OPSF has experienced a major fund deficit problem, which might be eliminated with an improved price adjustment mechanism. The remaining major concern with OPSF is that price stabilization requires price control. The following problems with oil product price control are dealt with in detail in the other sections of this report:

- **Prices indirectly set refiner margins (both limit and guarantee margins) Section 10.**
- **Controlled prices to consumers can encourage demand while price at refinery gate can discourage current production and needed investment for increased future volumes (This is referred to as economics distortion - Section 13).**
- **Controlled prices may not encourage efficiency improvement to reduce cost**

Figure 10-7



- Section 13.

10.6 Oil Price Stabilization - Other Options

Two approaches used by governments and companies in attempting to stabilize the price of crude oil are i)the establishment of strategic petroleum reserves by governments; and ii)the purchase of crude oil futures by companies.

The concept of the strategic petroleum reserve (SPR) is quite simple. Governments purchase and build up crude stocks in storage of about a 1-6 month supply. This stored crude oil can then be sold by the government when crude supplies become restricted on the market or the market experiences a major price increase. This serves to dampen the price escalation, diminish disruption to the economy and assure supply for domestic use.

Obviously, establishing a strategic petroleum reserve for the Philippines would involve a major cost outlay. For the initial fill the cost would be about 400 million dollars for a 20 million barrels reserve. Operating costs would include expenses for working capital and storage costs for tankage to maintain the reserve. A strategic petroleum reserve is an expensive "insurance policy". The cost of the SPR must be weighed against the economic cost of disruption resulting from a major cost increase times the probability of occurrence of such a price increase occurring. A country with an economy of the size of the Philippines may decide the potential benefits do not justify the cost. Moreover, it may be more appropriate to let economically advantaged countries with SPR programs attempt to moderate crude price increases in anticipation that the benefits will pass to the Philippines.

In former times, companies could protect themselves from crude oil cost increases by means of a longer term purchase contract. However, crude suppliers refused to honor contracts when prices doubled and tripled within a few months. The main mechanism of price protection has become the use of crude oil futures. Use of crude futures is analyzed in Chapter 12.

While oil price stabilization programs in the Philippines have not been able to protect the country from the negative economic impacts of rapid crude price rises, other options have also not demonstrated any record of success. The SPR programs which were developed in other countries in the 1980's are still untested because crude supplies have been in surplus in the past decade. The only major price spike occurred in August of 1990 during the Gulf War, and prices rose and fell back before a decision to use SPR reserves was made. By the same token, the impact of the crude futures market is also unknown, although it is used by companies to prevent negative margin performance.

10.7 Summary and Recommendation

The Oil Price Stabilization Fund (OPSF) was established to help stabilize petroleum product prices and minimize the frequency of price changes to the consumer. When the average c.i.f. price of crude is lower than the established crude price used in setting product prices the oil companies pay the difference into the OPSF. Conversely, when the crude c.i.f. price is higher, the oil companies withdraw the difference.

The frequency of price changes have been reduced through the OPSF price setting mechanism. The average price paid by the consumer has not been reduced since, ultimately, the full crude costs must be recovered in the market place.

Since the OPSF was instituted in 1984 it has experienced some major problems. Adequate changes in product prices have not always been timely. The Fund was allowed to incur deficits approaching 17 billion pesos (US$ 680 million) in November 1990 before prices were increased to offset the higher crude costs resulting from the Gulf war and other increases prior to the war.

If the OPSF is to be continued, an automatic price change mechanism should be implemented which would decrease the political pressures to maintain lower prices when crude price increase occur and should maintain the OPSF balance in a more acceptable range. A detailed model has been developed and described. A pro forma example of how it would work is discussed.

The OPSF has also been used to help achieve social goals through cross subsidization of "social" products through higher prices for "luxury" products. Examples were shown which illustrate how prices could be maintained through specific taxes rather than use of the OPSF mechanism. At the same time government revenue were held essentially constant.

Use of strategic petroleum reserves (SPR) for use to stabilize prices would not be prudent. The cost of establishing and maintaining an SPR is enormous. The Philippines should benefit from the SPR's of more economically advantage countries who attempt to moderate crude economically advantage countries crude prices through drawdown, or mere threat of drawdown, of very large reserves.

Table 10-3

OPSF Refined Product Price Adjustment - Definition of Variables

Total Cost of Refined Product - The total of all cost per liter for the month including crude cost, refiners gross margin (to cover operating cost and profit), allowed distribution expenses, duties and taxes.

Product Revenue Per Liter - The revenue from the sale of the refined products produced from a liter of crude (assume refinery fuel use is 5%) at the controlled prices.

OPSF Change - The change in OPSF is the difference between the Total Cost of Refined Products and the Product Revenue per month.

OPSF End Balance - The end of month balance of the OPSF: Previous month's OPSF End Balance + current month's OPSF Change.

OPSFMAXB - A target maximum level set for the OPSF, when it appears that maintaining current product price settings the maximum will be or has been exceeded, then reductions in prices are made.

OPSFMINB - A target minimum level set for the OPSF, when it appears that maintaining current product price settings the OPSF will fall below the minimum level for the fund balance, then increases in prices are made.

OPSFBUFF - An amount that is added to OPSFMINB and subtracted from OPSFMAXB to give early anticipation of need for price change to improve probability of not exceeding target levels.

ACCFAC - In times of rapid crude price change, a greater price change adjustment needs to be made. The acceleration factor (ACCFAC) permits increasing the price adjustment based on how rapidly Total Refined Product Cost Per Liter is changing.

OVERCORR - When the maximum or minimum balance levels have been passed an over correction needs to be made to either rebuild or draw down the balance. The magnitude of OVERCORR determines the pace of building or drawing down OPSF.

Table 10-4

OPSF Refined Product Price Adjustment Routine - Logic

STEP 1	Assume change in OPSF will be the same next month as it was this month, and estimate next month's end of month balance: OPSF(m+1)
STEP 2	If OPSF(m+1) > (OPSFMINB + OPSFBUFF) and OPSF(m+1) < (OPSFMAXB - OPSFBUFF) then no price change need to be made, GOTO STEP 7.
STEP 3	If OPSF(m+1) < (OPSFMINB + OPSFBUFF) or OPSF(m+1) > (OPSFMAXB - OPSFBUFF) then price changes may be needed, GOTO next STEP.
STEP 4	Calculate Price Adjustment Multiplier: (Six month avg. of Total Cost of Refinery Products Per Liter) - (Product Revenue Per Liter, current Month) + ACCFAC * (Current Cost Per Liter - Six Mon Avg Cost Per Liter)^3)*OVERCORR
STEP 5	Second Check on Price Adjustment: If fund deficit is anticipated in following month, only price changes should be increase and if fund excess is anticipated, only price change should be decrease. If sign of Price Adjustment Multiplier is consistent with deficit (+) or excess (-), then next step, if not GOTO STEP 7
STEP 6	Calculate price changes for all products by multiplying Price Adjustment Multiplier times the individual Price Adjustment Factors. Then add price changes to current prices to determine prices for next month. GOTO STEP 8
STEP 7	No price changes to be made, next month prices = current. GOTO STEP 8
STEP 8	END of calculations for current month.

11 ECONOMIC IMPACT OF DIFFERENT PETROLEUM PRICING REGULATION

This chapter discusses computer modeling procedures to assess the economic impacts of different petroleum pricing regulations.

11.1 Description of the Model

A monthly econometric model was constructed to quantify the economic impact of different petroleum product pricing scenarios. The model consists of eleven structural equations, which in turn have been subdivided into three blocks: i)prices; ii)petroleum demand; and iii)real sector. The Cochrane-Orcutt method was used to correct serial correlation in the model.

11.1.1 Prices

The block consists of four structural equations with seven exogenous and five endogenous variables. The equations of this block are as follows:

$$(1)\quad NLR = F(\overset{+}{SDR}, \overset{+}{TDR}, \overset{+}{TBR91}, \overset{+}{RRR}, \overset{+}{INFL})$$

$$(2)\quad CPIL = F(\overset{-}{WPPAVE}, \overset{+}{CPIL(-1)})$$

$$(3)\quad CPIM = F(\overset{-}{WPPAVE}, \overset{+}{CPIM(-1)})$$

$$(4)\quad CPIH = F(\overset{-}{WPPAVE}, \overset{+}{CPIH(-1)})$$

$$(5)\quad CPIA = F(\overset{-}{WPPAVE}, \overset{+}{CPIA(-1)})$$

where: NLR is the nominal loan rate (%)

SDR is the savings deposit rate (%)

TDR is the time deposit rate (%)

TBR91 is the 91-day treasury bill rate (%)

RRR is the reserve requirement ratio (%)

INFL is the inflation rate (%)

WPPAVE is the average wholesale posted price of petroleum products (P/liter)

CPIL is the consumer price index (CPI) for the low income class

CPIM is the consumer price index for the middle income class

CPIH is the consumer price index for the high income class

CPIA is the consumer price index for all income classes.

Equation 1 embodies the hypothesis that the nominal loan rate is directly proportional to the savings deposit rate, the time deposit rate, the 91-day treasury bill rate,the reserve requirement ratio, and the inflation rate.

Interest rates are primarily affected by the cost factor arising from the bank's operations to generate and lend funds. As such, changes in the intermediation costs (or bank costs) are assumed to be passed on to end-users or borrowers of funds. Higher bank costs mean higher loan rates. It is also assumed that banks, more or less, maintain a fixed profit margin for a given level of demand for credit. The intermediation costs are represented by: i)savings deposit rate; ii)time deposit rate; and iii)reserve requirement ratio.

Being reflective of the cost of funds, the treasury bill rate has an important role in the portfolio choice of banks. These rates reflect the need for the government to source funds from the domestic money markets. To ensure an attractive "price" for these government-backed securities, rates are raised to competitive levels--putting pressure on nominal lending rates. Hence, the 91-day treasury bill rate reflects the opportunity cost of funds of banks.

The inflation rate is regarded indirectly as an indicator of the rise in the average costs of processing and administering bank loans. Inflation is utilized as a benchmark for the average rate of price increases of goods and services. Since banks want to maintain a certain profit margin, any increases in costs are eventually passed on to end-users in the form of higher loan rates.

Equations 2-4, on the other hand, embody the hypothesis that the consumer price indices across income classes are directly proportional to the average wholesale posted price of petroleum products and the CPI, lagged by one period.

The country remains heavily dependent on imported crude oil for its energy needs. Currently, imported crude oil accounts for over 65% of Philippine primary energy consumption. Thus, petroleum products are important inputs in major industries, particularly in power generation and land and water transport. Hence, any increases in petroleum product prices would imply higher operating costs for these industries, which will eventually be passed on to consumers through higher prices.

The one-month lag of CPI was included since higher prices cause individuals to speculate in the short-run, and to cut back as the condition is prolonged. This reflects the fact that consumers adapt to the most recent economic phenomena. Because information is scant, they tend to expect past prices to prevail in the near future.

11.1.2 Petroleum Demand

This block contains four demand functions: (1) fuel oil; (2) diesel; (3) gasoline; and (4) LPG. The specifications of these equations are as follows:

$$(6)\ DFO = F(\overset{-}{WPPFO}, \overset{+}{NPC})$$

$$(7)\ DDSL = F(\overset{-}{WPPDSL}, \overset{+}{INDXPROD}, \overset{+}{DSLVH}, \overset{+}{DDSL(-1)})$$

$$(8)\ DGAS = F(\overset{-}{WPPGAS}, \overset{+}{WPPDSL})$$

$$(9)\ DLPG = F(\overset{-}{WPPLPG}, \overset{+}{INDXPROD}, \overset{+}{WPPKERO}, \overset{+}{DLPG(-1)})$$

where: DFO is the demand for fuel oil (MB)

DLPG is the demand for LPG (MB)

DDSL is the demand for diesel (MB)

DGAS is the demand for gasoline (MB)

WPPFO is the wholesale posted price for fuel oil (P/liter)

WPPLPG is the wholesale posted price for LPG (P/liter)

WPPDSL is the wholesale posted price for diesel (P/liter)

WPPKERO is the wholesale posted price for kerosene (P/liter)

INDXPROD is the index of production

DSLVH is the number of diesel-powered vehicles (in thousand)

NPC is the NPC energy sales (in gigawatt hours).

Each equation includes the price of the petroleum product whose demand is being estimated. Since these are demand functions, an inverse relationship exists between the quantity demanded and the price.

In equation 6, NPC was included since its the largest consumer of fuel oil in the country.

In equation 7, the variable INDXPROD was used as a proxy for gross value added (GVA) in industry. This variable captures economic activity in the industrial sector, while DSLVH was included as an explanatory variable since the land transport industry is the second largest diesel consumer.

WPPDSL was incorporated into equation 8 as an attempt to capture interfuel substitution. Because of the large price differential between gasoline and diesel, a large number of consumers are now shifting to the latter, distorting the petroleum product consumption pattern. The positive coefficient of WPPDSL is due to the fact that any increases in diesel prices result in greater demand for gasoline.

Equation 9 incorporates the price of a substitute product (WPPKERO) and a proxy variable for industrial activity. A one-month ** of the dependent variable was included to capture demand expectations.

11.1.3 Real Sector

In order to capture the link between the energy sector and economic growth, the following equation was specified

$$(10)\ NPC = F(\overset{-}{WPPFO}, \overset{+}{INDXCOMP}, \overset{+}{NPC(-1)})$$

where: INDX is the index of compensation.

Since monthly GNP is currently unavailable from the National Statistical Coordinating Board, NPC was used as proxy variable. Equation 10, in this case, is a combined demand and production function. It is a demand function since it includes a price variable, which is inversely proportional to the dependent variable. On the other hand,

it is a production function since a labor variable was incorporated, to which the dependent variable in directly related. Again, the lagged value of NPC was included to reflect demand and production expectations.

In order to translate the movements in NPC to growth in GNP, the assumption that <u>every 1.27% growth in NPC energy sales means a 1% growth in real GNP</u> was used. This is the same assumption used by the NPC is estimating impact of energy sales to economic growth.

11.2 Economic Impact of the Petroleum Product Price Deregulation

In quantifying the economic impact of the petroleum price deregulation six pricing schemes were examined. The analysis of the oil pricing impact assumes a crude oil price of $20.00 per barrel, which is relatively higher that the import price currently facing the domestic petroleum industry.

The pricing schemes used in the analysis are as follows:

- Case A: status quo - current prices are maintained and the drawdown from the OPSF will continue;
- Case B: balanced OPSF - existing tax rates will be retained and the prices will be adjusted with OPSF monthly change forced to zero;
- Case C: No OPSF - the OPSF will be eliminated and the prices are those

which would occur without the OPSF and with the current taxes and duties;

- Case D: Restructured Tax - the OPSF will be eliminated and tax and duties will restructured to achieve the prices of Case B;

- Case E: No OPSF but the price of gasoline and avturbo has been increased and kerosene and diesel prices have been reduced - OPSF will be eliminated and the tax rates will be restructured; and

- Case F: No OPSF but the price of diesel and kerosene has been increased and heavy fuel oil prices have been decreased - OPSF will be eliminated and the tax rates will be restructured.

Using Case B as the reference point, petroleum product prices would be at their lowest in Case A as shown in Table 11-1. On the other hand, prices would be at their highest in Case C--with diesel, fuel oil, and LPG prices expanding by 4.0%, 19.8%, and 28.1%, respectively. This is not surprising since these three products are currently being subsidized through the OPSF. The price of diesel and kerosene will be highest in Case C, bacause the current duties and taxes are not restructed with decontrol.

Table 11-1

Petroleum Product Prices: Pesos/liter
(percentages are changes versus Case B)

	A	B	C	D	E	F
	current	balanced OPSF	no OPSF	Restructured Tax	no OPSF up gas/jet	no OPSF up die/kero
Gasoline (avg)	10.75	11.88	9.50	11.88	13.63	11.87
	-9.51%		-20.03%		14.73%	-0.08%
Aviation Turbo	13.39	13.50	9.15	13.50	13.50	13.50
	-0.81%		-32.22%		0.00%	0.00%
Fuel Oil	2.85	3.23	3.87	3.23	3.23	2.85
	-11.76%		19.81%		0.00%	-11.76%
Diesel Fuel	7.00	7.30	7.59	7.30	6.75	7.60
	-4.11%		3.97%		-7.53%	4.11%
Kerosene	7.00	7.30	7.74	7.30	6.75	7.60
	-4.11%		6.03%		-7.53%	4.11%
LPG	5.26	5.26	6.74	5.26	5.26	5.26
	0.00%		28.14%		0.00%	0.00%

Considering the substantial price increases in diesel and fuel oil under Case C, it would be under this scenario that the economy would experience the greatest dislocation and disruption. This is to be expected since these two products are important inputs in the industrial sector. Relative to Case B, real GNP will contract by 2.9% under the said scenario, which implies that per capita income will drop 5.4% (Table 11-2). Hence, this scenario is definitely politically less desirable. Moreover, the CPI will increase by 0.3% for this case, meaning the most negative impact on consumers.

Table 11-2
Effects of the Petroleum Price Deregulation
(percentages are changes versus Case B)

	—A—		B	—C—		D	—E—		—F—	
	level	change		level	change		level	change	level	change
DEMAND (in M kilos)*										
Diesel Fuel	6.06	1.5%	5.96	5.88	-1.5%	5.96	6.13	2.8%	5.87	-1.5%
Gasoline	2.07	4.4%	1.98	2.17	9.3%	1.98	1.85	-6.8%	1.98	0.0%
Aviation Turbo	0.18	0.2%	0.18	0.19	8.0%	0.18	0.18	0.0%	0.18	0.0%
Fuel Oil	5.39	2.8%	5.24	4.99	-4.8%	5.24	5.24	0.0%	5.39	2.9%
Kerosene	0.65	1.0%	0.65	0.63	-1.4%	0.64	0.65	1.8%	0.63	-1.0%
LPG	0.87	0.1%	0.86	0.48	-44.1	0.86	0.86	0.0%	0.86	0.0%
PRICES**										
CPI Low Income	198.0	-5.9%	210.4	211.0	0.3%	210.4	210.5	0.1%	210.3	-0.0%
CPI Middle Income	197.0	-6.0%	209.6	210.2	0.3%	209.6	209.7	0.1%	209.5	-0.0%
CPI High Income	207.2	-5.7%	219.7	220.3	0.3%	219.7	219.8	0.1%	219.6	-0.0%
CPI All Income	200.6	-5.8%	213.0	213.6	0.3%	213.0	213.1	0.1%	212.9	-0.0%
Nominal Loan Rate (%)	19.39	-0.4%	19.46	19.47	0.0%	19.46	19.47	0.0%	19.46	-0.0%
ECONOMIC GROWTH***										
NPC Sales (000gwh)	17.1	2.2%	16.7	16.1	-3.7%	16.7	16.7	0.0%	17.1	2.2%
GNP Growth (1985 PB)	711	1.7%	699	679	-2.9%	699	699	0.0%	711	1.7%

Case A: Current
Case B: Balanced OPSF
Case C: no OPSF
Case D: No OPSF Restructured Tax
Case E: no OPSF; up gasoline and avturbo
Case F: no OPSF; up diesel and kerosene

* Case A include May to June 1992 figures
** Case A include July 1992 figures
*** Case A include annualized 1992 figures

Case D has the same price as Case B and consequently the economic impacts are identical. The importance of this case is the recognition that the same prices can be achieved with or without OPSF if the tax and duties are restructured.

Case A will result in the least economic dislocations. In fact, under this scenario, a 1.7% increase in GNP will be experienced. In addition, CPI and the nominal loan rate will shrink by 5.8% and 0.4%, respectively. This case simply demonstrates that lower oil product prices benefit the economy and the people. But it is a case in which OPSF is being drawn down, that is, oil product prices are being subsidized. That can only be continued for a limited time and then OPSF balance must be increased, at which point the prices would be higher than Case B or D, and GNP and CPI would be less attractive than those of comparative cases.

Case F will likewise result in a 1.7% expansion in GNP relative to Case B. However, the drop in the CPI and the nominal loan rate will not be as significant as Case A. Moreover, this scenario calls for the restructuring of the existing taxes imposed on petroleum products. The tax restructuring will, of course, require Congressional approval. Currently, a number of tax measures are pending in the House. With the country's tight fiscal targets with the IMF, the legislature will be hesitant to enact measures that will result in lower government revenues.

Oil product prices affect GNP and consumer prices. The GNP is most sensitive to heavy fuel oil prices. It is the allocation of taxes (and duties) to the individual products that is the key energy policy decision that will determine relative prices and hence economic impacts. Currently, the oil product pricing mechanism through OPSF plays a role in shifting the allocation of taxes and duties between products as crude prices rise and fall. As discussed in Chapter 5, restructuring taxes and duties would give approximately the same prices with or without regulation. Thus, strong consideration should be given to the effect of oil tax on the economic impacts of oil pricing in addition to regulation versus deregulation, since much the same results can be obtained in either environment given a decision on taxes and duties.

11.3 Summary and Recommendations

A monthly econometric model was developed to quantify the impact of product prices of varying pricing scenarios. This model was linked to a petroleum demand model reflecting change in demand of fuel oil, diesel, gasoline and LPG with price.

Six scenarios were defined and the results on certain aspects of the Philippine were investigated. The cases reviewed were:

Case A	Status quo. Current prices maintained and OPSF drawdown continues
Case B	Prices changed to force OPSF to balance
Case C	OPSF eliminated. Prices as current excluding OPSF add on/subsidy
Case D	OPSF eliminated but taxes restructed to achieve the same prices as in Case B

Case E	OPSF eliminated, taxes restructed as in B, gasoline and avturbo prices increased and kerosene and diesel decreased
Case F	OPSF eliminated, taxes restructured, kerosene and diesel prices increased, fuel oil decreased

Case A shows the best effect on the economy which should be expected since it assumes a continual drawdown of the OPSF (ie subsidy to the economy) which is not possible.

Case C would be the most disruptive to the economy with a 2.9% reduction in GNP, a decrease of 5.8% in per capita income, an increase of 0.3% in CPI, decrease the nominal loan rate by 0.4%, all relative to Case B, current sustainable case. This is to be expected since both diesel and fuel oil would lose subsidation through the elimination of the OPSF and both products are important inputs to the industrial sector.

Case D has the identical impact as Case B since prices are the same by definition.

Increasing gasoline and avtur with offsetting increase in kerosene and diesel as reflected in Case E would have little impact.

Decreased fuel oil prices with offsetting increases in kerosene and diesel would increase the GNP by 1.7%, and have essential no effect on the average per capita income, CPI or nominal loan rate.

12 PETROLEUM PRODUCT PRICES, TAXES, AND REGULATORY PRACTICES IN OTHER COUNTRIES

In this chapter the prices, taxes and regulatory practices applicable in the Philippines are compared with those used in other countries. A data base pertaining to 60 countries was used in this comparison. Data for the rest of the world was not available, but this does not imply that the existing data is not representative. The data are for the summer of 1992.

12.1 Petroleum Product Prices and Taxes - Philippines versus Other Countries

The user price and tax content of the petroleum products under consideration are analyzed below.

12.1.1 User Prices

Table 12-1 shows the percentage of the user prices, in the 60 countries under consideration, which are higher than those in the Philippines. Figure 12.1 displays these results graphically.

Table 12-1

PERCENTAGE OF COUNTRIES
WITH PRODUCT PRICES HIGHER
THAN IN THE PHILIPPINES

	Percentage
LPG	55
Regular Gasoline	75
Premium Gasoline	74
Diesel	73
Jet Fuel	7
Kerosene	55
Heavy Fuel	57

12.1.2 Taxes and Special Levies

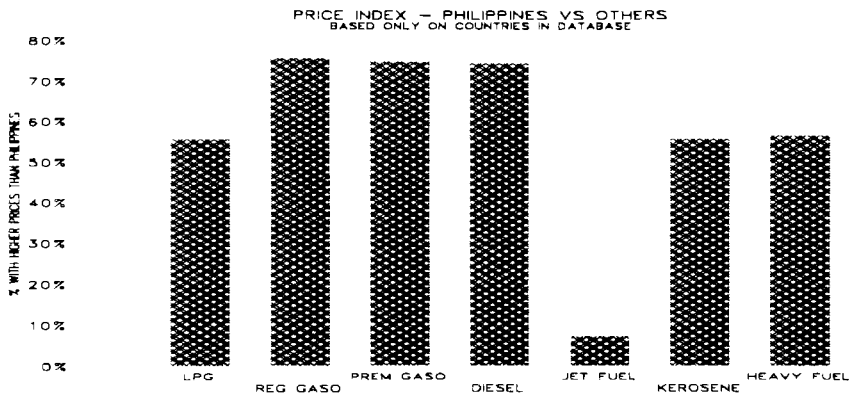
A significant component of the product prices is taxes and special charges levied by governments. In Table 12-2 the percentage of the 60 countries in the data base with taxes and special charges greater than those levied in the Philippines are listed. Figure 12-2 depicts these results.

Table 12-2

PERCENTAGE OF COUNTRIES WITH
TAXES AND LEVIES HIGHER THAN IN THE PHILIPPINES

	Percentage
LPG	41
Regular Gasoline	78
Premium Gasoline	83
Diesel	76
Jet Fuel	10
Kerosene	36
Heavy Fuel	31

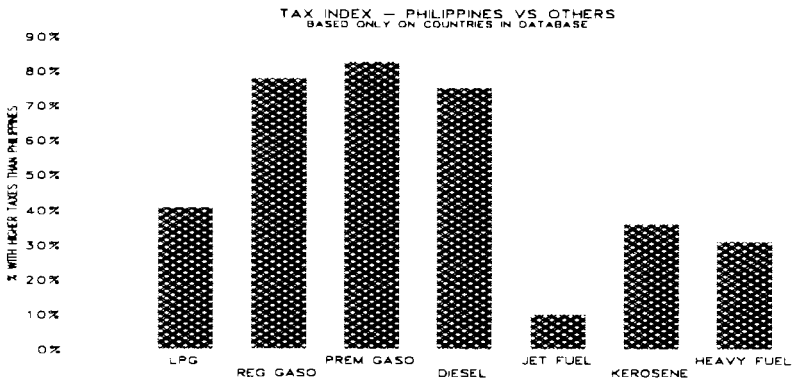
Figure 12-1



The tax data do not include items similar to the Philippine regular ad-valorem import duty (19%). However the data base apparently does include such items as the "special duty" of one peso per liter imposed in the Philippines.

Price and tax data for individual countries for each of the products are shown in Figures XII-3 through XII-9 in the Appendix. The data is presented graphically and ranked based on price.

Figure 12-2



12.2 Regulation of Petroleum Product Prices in Other Countries

A recent survey of sixty countries by "Energy Detente" revealed that there is a definite trend towards the decrease of the degree of government control of petroleum product prices. Between 1984 and 1991 the proportion of countries with price controls on all products decreased from 63% to 22%. Countries with controls on some products increased from 13% to 48% while those with no controls increased from 24% to 30%.

Of the countries in the Asia-Pacific included in the survey (the Philippines and other neighboring countries were not included in the survey), the following status was reported:

- With government controlled prices - India and Indonesia
- With some government controlled prices - New Zealand and South Korea
- Without government intervention - Australia, Japan, Singapore and Thailand

Government price regulation takes several forms:

- Set fixed prices - Usually these are set below world market levels and are typically applied by oil producing and exporting countries
- Established ceilings on prices - This method is more common in countries which import most of their energy requirements
- No controls - This usually occurs in industrialized nations

The prices of gasoline and diesel are controlled to some degree in 60% of the countries. These are also the most controlled products. Some control of LPG, kerosene and fuel oil prices exist in about half of the countries. Lubricants are the least controlled products.

12.3 Highlights of Price Regulation in Selected Countries

The following are the general characteristics of price regulation in several countries.

12.3.1 Bolivia

The Bolivian government sets the prices for all petroleum products except lubricants and greases. Prices are based on a combination of government revenue needs, social concerns, inflation and minimum wage rates. Taxes on diesel and gasoline account for about 65% of their retail prices. This is a large source of revenue for the government. When arriving at price levels, government revenue requirements are tempered by concerns for inflation, wage rates and social unrest. Prices in late 1991 were about 58% greater than in June 1990.

A measure was approved in November 1991 to abolish the government oil monopoly and encourage private enterprise in all phases of the oil industry, including refining and marketing.

12.3.2 Chile

The total refining capacity of Chile, 143,700 barrels per day as of January 1, 1993, is owned by the National Oil Company, Nacional del Petroleo (ENAP).

The government does not control petroleum product prices except for natural gas. Industrial users and distributors are free to import their petroleum products if better bargains can be found than supply from ENAP. Since Chile is net short of product, this system appears to be satisfactory to the several participants.

ENAP's pricing policy is to maintain relatively stable prices during world market upheavals. ENAP prices are generally not changed until stability is reached on the world market scene.

A Crude Oil Stabilization Fund was established in late 1990 to assist in maintaining stable prices. Consumer prices are subsidized by the Fund during periods of rapid increases in world oil prices and is replenished with taxes during stable periods.

Tax rate were reduced following the rapid increase in world oil prices resulting from the Iraq/Kuwait conflict in 1990. When prices decreased the tax rates were increased to replenish the Crude Oil Stabilization Fund.

12.3.3 South Korea

South Korea has had the largest rate of growth of energy consumption in the world. Petroleum supplies over 50% of its energy needs. Petroleum consumption has increased over 60% over the past three years. Refining capacity has increased steadily and stood at 1,147,100 barrel per day at January 1, 1993. With the increased capacity imports of light products should decrease and exports of heavy products should increase.

South Korea has been gradually moving away from government controlled prices. Premium gasoline was decontrolled in 1989 followed by regular gasoline and kerosene in 1991.

Prices for bunker fuel, diesel, LPG, and jet fuel continue to be set by the government. Prices are based on the landed cost of crude, refining costs, oil product duty, distribution costs and margins, excise taxes and a value added tax. Gasoline prices increased about 6-7% following deregulation.

The excise taxes on petroleum and the duty on petroleum imports are serve as partial contributors to the Petroleum Business Fund. This fund was established in 1979 to be used to finance oil stockpiling, quality control, alternative energy sources and diversification of oil import sources.

Recently, import duties have been increased by up to 5% in order to decrease the dependency on imported products.

12.3.4 Thailand

Thailand refiners are free to set their own prices but are required to report prices to the government. Prices are reflective of world free market prices.

Prices had been controlled by the government but were deregulated in 1991. Previously government dictated prices based on refinery gate prices (linked to Singapore refinery prices), plus taxes, a government set marketing margin and contribution to the Thailand Oil Fund. The Oil Fund was established following the Gulf war in 1990 to help stabilize prices. Gasoline is heavily taxed, accounting for about 60% or retail prices. Diesel is subsidized with a tax rate of 10% less than premium gasoline.

At the end of 1992 Thailand had three refineries with capacity totalling 220, 550 barrels per day. About half of its petroleum products are imported. With two additional refineries under construction Thailand should be self sufficient upon their completion. Thai Oil is completing a 100,000 barrel refinery and Shell's 145,000 barrel refinery is scheduled for completion in 1994.

Thailand refiners are protected against low priced competition through a surcharge on gasoline, kerosene, diesel, fuel oil, and LPG imports.

12.3.5 Venezuela

All petroleum products prices are controlled in Venezuela and have been among the lowest in the world. In August 1991 the government began increasing the prices on a monthly basis.

Table 12-3 shows the evolution of taxes on products for the period July, 1991 to December 1992.

Figure 12-3

CHANGES OF TAXES ON PETROLEUM PRODUCTS
IN VENEZUELA
(In Percentages)

	Jul 1991	Dec 1991	Dec 1992
Premium gasoline	15	34	51
Regular gasoline	15	36	63
Diesel	0	27	50

The resulting prices of products increased accordingly. Thus:

- In December 1991 gasoline prices were 80% higher than June 1990.
- Premium gasoline prices in December 1992 were 73% higher than in December 1991 while regular gasoline was 52% higher.
- In December 1991 the price of diesel was four times the June 1990 price and in December 1992 was an additional 44% higher.

12.4 Summary and Recommendations

Comparisons were made of consumer prices in the Philippines and those of 60 other countries for which prices were available. The data shows that consumer prices for gasoline and diesel are higher in about three fourths of the countries in the survey than they are in the Philippines. Prices for kerosene, LPG and fuel oil are higher in a little over half of the other countries. Prices for jet fuel in the Philippines were among the lowest for which there were data.

Taxes contribute a large part of the consumer prices in most countries. Comparison of taxes in the Philippines present a pattern similar to that of total consumer prices. Taxes on gasoline and diesel were higher in more than three fourths of the other countries. Kerosene, LPG and fuel oil had higher tax rates in 30-40% of the countries than that of the Philippines.

Overall, based on the survey data, petroleum product prices in the Philippines are more favorable to the consumer than they are in most countries of the world. This is largely due to the lower tax burden in the Philippines.

There is a definite trend to decrease the amount of control of product prices throughout the world. Countries with price controls on all petroleum products decreased from 63% in 1984 to 22% in 1991 while those with no price controls increased from 24% to 23%. Those with price controls on some but not all products increased from 13% to 48%.

A review of regulatory history in Bolivia, Chile, South Korea, Thailand and Venezuela indicate that regulations are being relaxed and price movements toward world market prices are being effected. Several of the countries had funds somewhat similar, but not utilized in exactly the same manner, to the Philippines Oil Price Stabilization Fund.

13 CONTROL VERSUS DECONTROL OF OIL PRODUCT PRICING

Several factors affect the issue of whether pricing of petroleum products should or should not be controlled. The effects of these factors are discussed in this chapter and five alternatives of control/decontrol are then presented.

13.1 Economic and Social Equity

Economic and social impacts are a function of product prices. This impact is further affected by both the overall level of prices for all products and the relative prices of the individual products. Since approximately the same price levels can be achieved with either control or decontrol, there would be no significant differences in impact to the economy or the population if either of the techniques were used. Some of these impacts are described below:

(a) Duties and taxes on crude and oil products can be restructured to provide approximately the same product prices to users while maintaining the same revenue generation.

(b) Crude cost, taxes and duties represent over 80% of the consumer cost of oil products, the remaining 20% being operating costs and margins. Thus, even if the operating costs and margins change significantly, the impact on the consumer prices, and hence on the economy or population, will be small.

(c) Most of the time, price fluctuations in oil product prices will have little impact on the economy, although the population may experience some adjustment problems due to price fluctuations with decontrol. Major oil price spikes will produce economic disruptions regardless of whether price controls and/or oil price stabilization programs are used.

(d) It would be desirable to establish a new means of adjusting the fares for public transport when the cost of fuels change appreciably.

13.2 Product Supply and Production Efficiency

Supply problems are now occurring in the Philippines as a consequence of inappropriate oil product price setting at the refinery gate. It is possible to make changes to the Philippine refinery gate price setting procedure that would improve the process and diminish the current supply problems. The need for these changes existed for some time. It is not unusual in a regulated environment that similar difficulties are recognized belatedly, only after the problem has become severe. Proper corrections often require a time consuming trial and error process. These corrections can be achieved in several ways:

13.2.1 With price decontrol

Elimination of the current crude and product duty structure will enable refiners and marketers to better use imports and exports along with production to meet market requirements for products. Also, the resulting competitive pricing at the refinery gate would lead to refinery production decisions that would increase efficiency.

Decontrol would give incentives to supply products to meet demand. Middle distillate and heavy fuel imports would be used by refiners and other to balance domestic production. The refinery gate price of diesel would be higher relative to gasoline when compared with current controlled prices. The result of this would be that refiners could optimize their production to reflect market prices, and thus provide product to consumers more efficiently.

The inter-relationship between pricing and demand is relatively easy to determine in the decontrolled environment because the market provides clear signals of what changes are required. Price fluctuations and variations are, in fact, the mechanism by which production, inventories, and product distribution are continuously adjusted to supply the needed product in the right amount to the right places.

13.2.2 With price control

Effective setting of the relative prices of oil products can be an exceedingly difficult task for a regulatory body. Comparative pricing of oil refining product is more complex than the equivalent price setting for regulated gas or electric utilities. This is because no two refinery facilities are alike and the mix of multiple feedstock and product processes give rise to a large combination of differing outputs which are difficult to analyze and compare.

Neither sophisticated analysis nor complex industry simulation models (which are tools available to the regulator) can approach the inherent ability of prices, in the free market, to communicate efficiently between buyer and seller.

13.3 Meeting Future Processing Facility Needs

In an uncontrolled price environment refiners would be better able to predict future product requirements by normal forecasting methods, whereas this type of prediction would not be feasible in a controlled situation, where changes in regulatory guidelines are not predictable.

If the refiner can foresee changes of product requirements, he can better estimate the economic merits of facility investment alternatives.

13.4 Oil Company Competition and Margins

Present practice in the Philippines controls refiner's average margins. However, the existing procedures do allow for the improvement of some of the individual refiner's margins.

13.4.1 Possibilities of competition within the controlled environment

In the current price controlled environment average industry margins are set by ERB. Since regulation is based on average margins and costs, some degree of competition is still feasible within the existing system if the operations can be made to yield better than average results. Some of the areas where these advantages can be obtained are:

(a) Individual companies are rewarded for energy conservation and reduction of fuel usage, since margins are based on an assumed usage of 5% of crude change - an actual usage of less than 5% will be translated into a higher margin.

(b) Individual companies are also rewarded for performing better than the industry average in optimizing feedstock.

13.4.2 Control of Margins

In a price controlled environment the focus is always on how control limits margins, but control also guarantees industry margins. In a decontrolled environment companies are not guaranteed the relatively stable margins which exist with price controls.

In an uncontrolled milieu and a truly competitive market, the opportunity for increased margins is offset by instances of decreases. The variation of margins would be further exacerbated by the margins swings experienced by product import prices which reflect profit fluctuations in outside refining markets.

13.4.3 Competition

The fact that there are currently only three players in the Philippine oil product industry raises the concern that under price decontrol these players might behave oligopolistically and take advantage of the situation to extract excess profits. Restructuring of taxes and duties on imported products would help to avoid, or at least diminish, this situation. If duties on product imports were made very small or eliminated, then imports would compete with refinery operations and contribute to maintaining a competitive price level.

Imports will also create the opportunity for new entrants into the oil product market. Imports will be a constraint on domestic product prices and could suppress prices and margins when international product market are weak and excess product is available.

A second avenue to competitiveness would be the enforcement of a well-designed and monitored legal structure with authority to penalize any party that would indulge in pricing practices leading to non-competitive pricing or price fixing. It should be noted that this control is usually found in the anti-monopoly legislation of most civil law codes, rather than within one of the functions of a regulatory body. This mechanism should be flexible enough to be applicable to both the large producers (e.g. the refineries) or the medium or small distributor in remote areas where there is no competition.

13.5 Oil Price Stabilization

The established oil price stabilization program in the Philippines has achieved a reduction in the frequency of changes in oil product prices. Its main tools have been the OPSF and oil price controls. It does not follow that the country's economy and people have been protected from the disruptive impact of sudden changes in crude prices (such as a doubling from 20 US$/bbl to 40 US$/bbl). Nor will better price adjustment mechanisms eliminate the disruptive impact of a major price spike. The comparison between control and decontrol

must be based on the value of reducing price fluctuations in normal periods, since major price spikes will be a similar problem in either situation.

In a deregulated environment, the price of petroleum products will move with market forces. This means more frequent price changes compared to the present regulated environment.

The price fluctuations that come with deregulation will have an effect on the pricing of services where petroleum products account for a significant percentage of costs like electricity and transport. Will the public accept frequent changes in petroleum product prices, electricity and transport fares?

The public is already accustomed to frequent changes in their electricity rates since power utilities have fuel adjustment clauses which enable them to reflect movements in fuel prices in the billings to their customers. The situation is different in the transport segments, where different procedures are used for the major groups within the segment, as follows:

(a) In land transportation, the Land Transportation Franchising Regulatory Board (LTRFB) takes about two weeks to adjust transport fares to reflect a change in petroleum product prices. There have been instances in the past where jeepney and bus drivers have taken upon themselves to adjust transport fares because of increases in the cost of petroleum products even though the LTRFB had not yet authorized the new fares. This led to confusion and complaints.

(b) In sea transport, in the past, the Maritime Industry Authority (MARINA) took about six months to adjust inter-island shipping fares when petroleum product prices changed. However, it recently promulgated an executive order which allows it to adjust inter-island shipping rates within ten days when of the petroleum product prices changing by at least 10%. This scheme is scheduled to become effective in January, 1993.

In deregulated product environments buyers of large volumes protect themselves from price changes by term contract purchases and use of product futures. The jeepney and bus/truck drivers do not fall into the category of large volume purchasers and hence these avenues are not open to them.

It has been suggested that the regulatory process could limit the frequency of price changes on products such as diesel to once or twice a month. Probably this type of limitation is not in the interest of the customer since it does not assure the lowest prices and may even open the door to collusive pricing.

13.6 Revenue Generation, Taxes and Consumer Prices

Taxes on petroleum products are an important source of Philippine government revenue and are also a primary mechanism of implementing and balancing energy policy goals. The proportion of these taxes in comparison to the product price compares quite well with comparable taxation in many other countries. However, the existing taxation levels on different products have resulted in production distortions that affect the economy and require urgent modifications to both the energy policy and tax levels. Some of the most significant tax policy modifications are:

(a) Consumer pricing of gasoline and diesel - Because of a lower tax rate, diesel has been priced well below gasoline. Since the use of diesel has reached a level where production costs and problems of supply adequacy are increasing.

Energy policy and tax levels for the two products should be reviewed. One alternative that would reduce the impact on certain segments of transportation would be a tax that provides a differentially lower tax rate for public transport vehicles (that are users of a large proportion of the diesel production).

(b) Heavy fuel usage has a high impact on the economy since it is used extensively in the industrial and electric generation sectors. Presently heavy fuel tax rates in the Philippines are higher than in most countries. A revision of the existing policies and tax rates is important, because of the impacts heavy fuel consumption have on economic growth and the social well-being of the consumers.

In the Philippines, import duties and taxes on crude and petroleum products are based on a percentage of the respective landed costs. This policy has amplified the effect of crude price spikes on domestic oil product prices, producing undesirable impacts on social and economic goals. The current crude and products duty structure is also an impediment to achieving an efficient balance between domestic production and product importation. A possible solution would be to replace the existing taxes and duties with only specific product taxes which would result in the same (existing) consumer prices and would not affect the government revenue levels. This solution would:

- Simplify and clarify the role of taxes in energy policy
- Diminish the negative effects of price spikes
- Remove the need for OPSF's price adjustment role

The suggested tax and duty restructuring would be valid regardless of whether price control or decontrol are selected.

13.7 Options For Control And Decontrol

Six alternative control/decontrol policy options could be considered for oil product pricing:

13.7.1 Continuation of the existing OPSF and controlled pricing approach. (Option 1)

13.7.2 Continuation of the OPSF and adoption of a new "Automatic Price Change Mechanism". (Option 2)

13.7.3 Continuation of the OPSF, adoption of the "Automatic Price Change Mechanism", and restructuring of taxes and duties. (Option 3)

13.7.4 Elimination of the OPSF and decontrol of oil product pricing. (Option 4)

13.7.5 Elimination of the OPSF and price controls, restructuring of taxes and duties including a legal system that would penalize any attempt to reduce or eliminate competition. (Option 5)

13.7.6 Elimination of the OPSF and price controls, restructuring of taxes and duties without control of unfair practices that might reduce competition. (Option 6)

Each option is discussed below.

(a) Option 1 - Continuation of the existing OPSF and controlled pricing approach.

As discussed in Chapter 5, two major problems exist with the current oil price control mechanism: (i) the possibility of OPSF again developing a major deficit, and (ii) the current duty and tax structure in conjunction with the use of Singapore Import Parity prices has produced an inadequate supply of middle distillate product. These problems make this option unattractive.

(b) Option 2 - Continuation of the OPSF and adoption of a new "Automatic Price Change Mechanism"

The most prominently recognized problem with OPSF has been that at times serious balance deficits have arisen. Reluctance to increase prices, in the face of public and political pressure has meant price changes that were "too little and too late". The ultimate adjustment of the balance can only be deferred so long and, when corrective action must be taken, it has to be very severe.

To avoid the above traumatic corrections, an automatic price control mechanism was developed and proposed. It could virtually eliminate the deficit problem and would work as long as its implementation is free from political pressure and the implementing parties are committed to let it work. The process has been tested in a seven-year simulation with past and possible future crude market price swings and found to be capable of meeting desired energy policy goals.

(c) Option 3 - Continuation of the OPSF, adoption of the "Automatic Price Change Mechanism", and restructuring of taxes and duties.

As mentioned in the prior paragraph, the current duty on imported crude and product poses several problems for the refiners and marketers supplying product to Philippine consumers. Replacing duties with product taxes would make imports of middle distillate and exports of light naphtha and reformat more attractive and enable refiners to better balance the production mix of products.

Also, adjustments to the current basis of setting refinery gate prices should also be made to shift the marginal source of diesel fuel to imported product and the placement of the marginal gasoline/naphtha production in the export market.

Whereas these changes will help refiners and consumers in the short term, the longer term middle distillate demand growth problem will not be resolved by them.

(d) Option 4 - Elimination of the OPSF and decontrol oil product pricing

Decontrol of Philippine oil product prices without changes to the existing crude and oil product duty and tax structure would likely destine decontrol to failure because: (i) the resulting product prices changes would increase the middle distillate and decrease the gasoline prices (these price changes would be contrary to stated government energy policy objectives and would most certainly be met with strong

negative popular reaction), and (ii) the crude and product duties would continue to pose a problem in achieving efficient refining operation balance and would exaggerate the increase in diesel price.

(e) Option 5 - Elimination of the OPSF and price controls, restructuring of taxes and duties including a legal system that would penalize any attempt to reduce or eliminate competition

This option requires that a decontrol plan be structured to meet Philippine energy policy goals. In order to achieve those goals, duties and taxes on crude and oil products must be restructured as discussed previously.

Decontrol of prices should not be taken to mean that the producers and distributors would be free to stifle competition and consequently apply coercive and unfair pricing. There are legitimate concerns about competitiveness in an industry with only three companies currently in control of production, distribution and marketing channels. Thus the plan for decontrol should include the following:

- A clear statement to industry of government expectations on profits, price collusion and pricing in remote areas.
- A plan for the supply of industry statistical data
- A plan for describing the legal systems that would be available or would need to be developed to prevent anti-competitive practices in the production and distribution of oil products.

(f) Option 6 - Elimination of the OPSF and price controls, restructuring of taxes and duties without control of unfair practices that might reduce competition

This option is similar to Option 5 except that it assumes that the system to assure fair competition would be inoperative. It is shown only to stress the importance of having an operating system to assure competition, otherwise there would be too many opportunities to distort pricing against the interests of the consumers.

13.8 Comparison of Options

Clearly the most attractive option with price control is OPTION 3 and with price decontrol is OPTION 5.

13.9 The "Price Control" vs "Price Decontrol" Decision

The positive and negative aspects of oil price control and decontrol options have been analyzed. Whereas there are problems in dealing with oil product supply, demand and pricing with either control or decontrol, the analysis in this study shows that there would be more advantages than disadvantages if oil price decontrol is adopted.

Control vs decontrol is not a simple choice between black or white alternatives. Decontrol is recommended rather than attempting to improve the oil price control process in the Philippines. Table 13-1 summarizes the pluses and minuses of control and decontrol. As can be seen in the table, the positive aspects under control become the problems areas under decontrol and vice versa.

Table 13-1
POSITIVE AND NEGATIVE FACTORS OF PRICE CONTROL OR DECONTROL

Decontrol of Oil Product Pricing	
+	Market prices insure adequate supply to meet demand
+	Facility investors base decisions on perception of future market needs
+	Price competition encourages efficient production facility use
±	Price fluctuations are essential element of buyer/seller interaction
±	Price variation among sellers is indication of price competition
-	Limited numbers of suppliers causes concern about excess profits or pricing excesses (legal mechanism to eliminate reduction of competition)
Control of Oil Product Prices	
+	Can limit frequency of product price change
±	Limits but also guarantees margins
+	Assurance of moderate prices for remote and limited competition areas
-	Pricing may encourage inefficient use of production facilities
-	Decision making for facility investors more difficult: * Control masks market price signals * Success dependent on anticipating regulations not markets
-	Setting relative prices can create undersupply of some products
-	Pattern of remedial corrections based on past history creates problems

Since the choice between control and decontrol must take into consideration subjective factors, a thorough appraisal of the benefits and problems should be carried out prior to reaching a decision. Some of the questions that should be resolved are:

- Do the benefits of decontrol outweigh the new problems that must be handled?
- Is it wise to choose decontrol, if there is a high comfort level in maintaining the old and familiar?
- Is the feeling of comfort misleading? Are the weaknesses that now are starting to become apparent in the control alternative going to grow and become more difficult problems to resolve?

- Since decontrol and elimination of the OPSF will mean greater frequency of oil product price changes, is the public opinion going to accept these fluctuations readily?

After assessing the benefits and problems of Table 13-1 it is felt that decontrol is the more favorable option for the Philippines. With decontrol, refinery gate prices will reflect market forces and products will be provided in accordance with market needs. Refining and marketing operations will be more efficient and the consumer will see benefits, although they will appear modest because of the dominance of crude prices and taxes as components of consumer costs. Refiners will be better able and more willing to make new facility decisions to meet changes in product demand mix and to meet future environmental requirements for oil products.

Decontrol would add to the existing competition in the Philippine oil industry by fostering entry of additional competitors into the business. Product imports will also provide competition in oil product markets.

Decontrol would experience undue acceptance by the public if legal mechanisms are not in place to assure fair competition is in the production, marketing and distribution phases.

13.10 Implementation of Price Decontrol

Since price decontrols would be part of a process which would also include changes in energy policy, taxation of product and possible privatization, it would be futile to discuss it on its own merits. Thus it would be preferable to discuss some of the issues that may be included in the process, well understanding that a decision of the matter cannot be limited only to price decontrols. Two hypothetical scenarios for price decontrol will be discussed:

- Immediate decontrol
- Prompt decontrol - to be carried out as fast as the completion of each step permits

13.10.1 The constraints applicable to immediate decontrol could be such that this option would not be practical. Most of these constraints would be caused by there not being sufficient time to carry out the steps preliminary to the implementation of the process. Some of the issues that could not be resolved on short notice are:

(a) In order to implement price decontrols it may be necessary to pass legislation authorizing them or to modify the functions of the ERB to permit market forces to determine pricing. This process would also have to run concurrently with determinations of the role of the DOE in the matter. Price decontrol by legislative action might take some time given the high political sensitiveness of the issue.

On the other hand, there are people who think that decontrol can be brought about by executive action. Decontrol by executive action is risky because it can be challenged by legislators and private individuals in the courts. A court case would take considerable time to be resolved. Furthermore, some legislators could argue that the executive branch is usurping a legislative function. They would surely capitalize on the strong public bias against the oil companies

in general and multinational oil companies in particular. The legislators could also subpoena government and oil company officials to attend hearings in the legislature and make the proceedings a media event, another procedure that would introduce delays.

(b) In order to make decontrol palatable to the public it would be desirable that its application initially result in lower or, at the least, the same prices of petroleum products. In order to achieve this goal the timing of implementation should be made to coincide with: (i) stable or falling crude prices, (ii) stable or falling FOREX index, (iii) the OPSF balance has been building up. A long waiting period may be required until these conditions are met.

(c) Considerable time would be required to set up the administrative procedures and the price setting mechanisms required to work in an unfamiliar decontrolled milieu.

(d) The consumer would have to be educated to expect fluctuations in product pricing.

13.10.2 Prompt decontrol could be brought about in a great variety of ways. For illustrative purposes only, some of the steps that could be followed are:

(a) If the general public were to made aware of the cost components of oil product, there would be a better climate for the acceptance of fluctuating oil product prices. There are some cost issues that would lead oil companies to increase petroleum product prices. Some of the issues that should be resolved by ERB and the oil companies prior to decontrol are: (i) the loss of the forward cover would lead to higher working capital for the oil companies, the cost of which they would have to pass on to their customers, (ii) the oil companies' pending cost recovery petitions with the ERB and their claim that they are not earning enough from present operations should be settled (this should take into account the low margins (average 4.3% in the last five years) that the industry has been perceiving), (iii) the removal of the FOREX cover, and (iv) the cross-subsidies to socialized products through the OPSF.

13.11 Summary and Recommendations

Several factors affected by the control versus decontrol issues have been identified and discussed. These factors include:

1. economic and social equity,
2. product supply and production efficiency,
3. future processing facilities needs,
4. oil company competition and margins,
5. oil price stabilization,

6. government revenue generation and taxes, and

7. consumer prices.

Economic and social equity can be addressed equally well under control or decontrol. Supply problems have been compounded under controls and would be better resolved under a decontrolled environment. Oil companies would be in a better position to resolve investment issues absent unpredictable regulatory mandates. Competition among the oil companies is a legitimate concern with only three players but should be acceptable with proper governmental monitoring. Margins would be more volatile under decontrol. Oil prices would probably change more frequently in a decontrolled market but the average prices would not necessarily be higher. Government revenue could be maintained through proper restructure of taxes and duties.

Six scenarios of control/decontrol were analyzed. These were:

1. continuation of OPSF and controlled prices,
2. continue OPSF but with automatic price changes,
3. same as 2 but restructure taxes,
4. eliminate OPSF and price controls,
5. eliminate OPSF, decontrol prices, restructure taxes and include a legal system to penalize attempts to reduce competition,
6. same as 5 but no monitoring or structured penalties for non-competitive marketing.

Option 6. eliminate OPSF, decontrol prices, restructure taxes, and include a legal system to assure competition is considered the best alternative. It should assure reasonable prices to the consumer, government social goals and revenue objectives could be met through tax policies, refiners would be better able to project demand/prices for investment decisions and competition should be satisfactory. The other options would require additional governmental burdens and/or not provide sufficient competitive environment.

14 PRIVATIZATION, REGULATION, ENERGY POLICY, COMMODITY TAXATION AND PRICE CONTROLS

Most persons assign disparate images to the terms privatization, regulation and price controls. Thus the interpretations of the purposes and results to be obtained from these mechanisms may seem to be at first sight irreconcilable. However, a close understanding of the principles involved will show that the three tendencies can be made to work together to obtain the desired results, as discussed in this chapter

Often the terminology assigned to the three processes is loosely applied and confusion arises in the conceptual interpretation of the principles involved. For example, the term "deregulation" may be used to imply "price decontrol". The implications contained in the example will be discussed further in this chapter.

14.1 Privatization

To many people the term "privatization" conveys the acquisition of a government-owned enterprise by the private sector. Actually privatization implies the increase of the private sector's share of an activity where the government presently predominates.

Some of the characteristic of the activities that are suited for private sector involvement are discussed further.

14.1.1 Composition of the private sector. The two components are:

- The general public, whose individual holdings are relatively small, but because of the potentially large number of participants, could constitute an appreciable part of the sector. The general public has a minimal control on the management decisions of the enterprises it owns. Individuals may wish to borrow or purchase their stock holdings, but their equity may be considered to contain no debt.

- Large investors are effectively in control of the management decisions of the enterprises they own. Usually the investor's ownership is leveraged by a large proportion of debt.

14.1.2 Reasons and goals for the segments which form part of the asset or operation to privatize

(a) The Government may look favorably to privatization in order to obtain revenue, preferably in hard foreign currency, by selling its ownership of enterprises held by the public sector - often this revenue is used to decrease the deficit or the foreign debt. Argentina and Venezuela are successful examples of this procedure. Usually these sales are to groups of investors which are also experts in operating similar enterprises.

The Government may prefer to obtain revenue from the sale to the public from part or all of the equity of an enterprise it owns. This type of sale requires that the enterprise in question be considered,

by the public, to have an efficient and independent management structure. Great Britain and Thailand are prime examples of successful transactions of this type.

The Government may wish to sell some of its enterprises that are operated inefficiently or that produce inadequate profit margins. Purchasers would be interested in the transaction only if they would expect to increase the operating efficiency sufficiently to produce adequate margins, and/or purchase the enterprise at a very low price.

The Government may consider contracting out to the private sector some of the operations that traditionally are considered to be unique functions of the enterprise staff, as a means of attaining better operating efficiencies.

(b) Private investors will be interested in investing in enterprises which they consider to have potential for profits from this investment that are sufficient to justify the risks inherent with the operation of the enterprise. More interest will be shown by the investors, and more favorable conditions to the local economy will be obtained if the circumstances inherent to the investment reduce these risks.

The principal factors that guide the investor's assessment (a very subjective procedure) of the risks involved with a project are answered by responding to the following questions: (i) Is there a market for the commodities or services to be produced? (ii) Is the legal status of the project clearly defined so that no obstacles will arise in the transfer of any properties that may be involved and of the sale of the product? (iii) Is the Government legal position with respect to the project clearly defined? (iv) What assurance is there that prompt payment shall be made for the goods or services delivered? (v) What assurance is there for the interchangeability of foreign exchange to cover the repatriation of dividends and the original investment, pay the debt service, and assure the timely procurement of the materials, goods and services required for the production, operation and maintenance of the project? (vi) What assurance is there that the investor will be able to continue taking independent management decisions without undue government interference? (vii) Is there any restrictive labor legislation that would interfere with the investor's efficient utilization of the work force? (viii) Are the regulations for the protection of the environment sufficiently well-defined to enable the investor to calculate their cost to the project?

(c) If the general public is to purchase equity of the enterprise, it must have confidence in the project. This confidence will come from the public's estimation of the ability of the project to pay adequate dividends and/or exhibit potential for an adequate increase of the future value of the equity.

14.1.3 Justifications for privatization

The main arguments in favor of privatization are:

(a) In some cases the public sector is unable to obtain sufficient funds (including through borrowing) to invest in new projects. Given a favorable climate for the investment, the private sector may be interested in participating in the project, usually with the proviso that it have full autonomy in the decision-making process.

(b) It is commonly reckoned that the private sector should be more efficient in its operations. While this may be true in the majority of cases, there are many instances in which the public sector operates very efficiently.

It should be noted that it does not necessarily follow that the price of a commodity or service produced by an efficient private operator is lower than the equivalent that could be produced by the public sector, even if the latter is not very efficient. This is because, depending on the mix of financial (fixed) costs and variable costs applicable to the product, it could happen that the private sector would have to obtain financing at much higher interest rates than the public sector (assuming that the public sector could borrow the funds), which would increase costs.

14.2 The Regulatory Process

14.2.1 What is Regulation?

Societies live in accordance with a set of rules. These rules may be written or unwritten. All these rules compose the "regulatory process". Some of its main manifestations are:

- The civil and criminal right laws
- Policies issued by the central government, which include taxation
- Laws, ordinances and other regulation issued by governments that are not the central government
- Laws, ordinances, regulations and policies issued by "sectorial entities" which are made responsible to control the interaction with the rest of society of certain sectors or segments of this society.

The latter group is very often referred to as "Regulators". It should be pointed out that there may be several "regulators" that have jurisdiction over one sector or segment. For example, the oil industry may be under the jurisdiction (to mention a few) of: (i) DOE, (ii) ERB, and (iii) the groups that guide the preservation of the environment. Naturally, the industry will also have to abide to the laws of the land.

Theoretically, the degree of the control and the focus of this control should be dictated by the extent of competition within the sector or segment. Three examples of extremely different scenarios will illustrate the differences in the roles required from the regulators:

(a) If we assume the existence of a free market with nearly perfect competition, it would not be necessary to control prices, but it will be essential to increase the controls in other areas to insure that the free market and the competition are maintained. One solution would be to provide a strong legal mechanism to penalize the entities that indulge in monopolistic practices.

(b) If in the above scenario, competition is not perfect, in addition to the mentioned legal mechanism it may be desirable to limit the share of the market that may be held by one of the producers and/or put an upper limit to the margins that any of the producers may achieve.

(c) Assuming that prices are fully controlled, the regulatory procedures will automatically look into the anti-monopolistic issues and therefore the legal mechanism mentioned above may be superfluous.

14.2.2 A Brief History of "Sector" Regulation of Public Utilities

A brief history of how sector or segment regulation will show how some of its guiding concepts were developed.

Initially, the regulatory process was limited to establishing fares, schedules and minimum conditions of service and granting concessions defining areas of service to transportation companies. There is evidence of such regulatory mechanisms existing in England in the seventeenth century. This regulation recognized that since there was no competition among the providers of the services, within a given area, the consumer was to be protected.

Starting in the 1850's a strong regulatory movement was implemented in the U.S. to protect the public against price gouging and inappropriate financial practices carried out by some railways. Since there was not much possibility of competition when a railway served a certain area, the railways were, or approached being, a monopoly.

Since the 1850's regulatory practices were extended to most utilities serving the public. In the U.S., regulation acquired a high degree of sophistication. Many other countries developed regulatory climates, many of them inspired by U.S. practices. Regulation is justified in these instances because the public utilities are considered to be monopolies and, as such, could indulge in abusive pricing and render very poor service unless controlled by the regulatory process.

As regulation developed in the U.S. its goals became better defined as: (i) to protect the consumer against unfair pricing practices, (ii) assure that the quality of service meets certain minimum standards, (iii) assure the investors they will obtain a fair return on their investment.

In many countries the regulatory process shifted its emphasis to limiting its activities to tariff-setting and to establishing low rates (usually below cost), thinking that this procedure would result in a long-term advantage to the consumer. Often the pricing policies were set to comply with political pressures, rather than fair costing determinations. Unfortunately these practices resulted in the utilities not investing to expand their service and, in the long run, brought about a serious deterioration of service. (A sophisticated regulator will consider that establishing tariffs below the cost to provide service is a "confiscatory" practice, because it decreases the real value of the utility).

14.2.3 Regulatory Practices for the Private Sector

Regulation is required under all circumstances, otherwise society will live in complete chaos. Even if a society lost all its regulation powers, eventually it would be taken over by a few strong individuals that would impose their own rules. Thus the term "deregulation" should not be used.

Regulation must be capable to change its methods when circumstances change. A prime example of this would be the changes needed if price decontrol were brought about. As mentioned in Chapter 13, there are many advantages to price decontrol for the oil industry. This step is recommended, provided there is a policy decision to allow the free market to set the prices. Thus, the existing regulatory practices would have to be modified to deal with:

- Shifting the emphasis from price and margin controls to establish and enforce safeguards to assure competition.
- Modifying the taxation policies to produce desired social objectives and balance the supply/demand of oil products

14.3 Energy Policy and Taxation

It must be assumed that both the regulatory and the privatization processes (in the energy sector) are guided by an overall national policy whose main aim is to establish priorities and incentives. The government has the responsibility to state the energy policy and to provide the legal means to enable its implementation. These activities are beyond the scope of this report.

Taxation of petroleum products is a component of the energy policy, since it is an effective means to providing incentives (or dis-incentives) to the consumption of the product and it is also very useful in sending signals to the consumer (See Chapters 8 and 9)

14.4 Privatization of Petron

The issue of the privatization of Petron is not a matter that can be resolved without a thorough study of what steps and consequences may arise from any decision on the subject. Several possible scenarios will be discussed (including one where Petron is not privatized), mainly to outline some of the issues that may arise. It is recognized that some of these scenarios are improbable and unconventional, however, they have been presented as a means to underscore some of the pertinent issues. Since the alternative selected is dependent on policy decisions that must be taken by the energy sector, no recommendations are going to be put forward in favor or against any of these scenarios.

14.4.1 Scenario 1 - Sale of Petron's facilities to a private enterprise

The following assumptions would apply to the scenario:

- Petron's refinery, terminals, distribution and marketing facilities would be put on sale through an international bidding process.
- Clear-cut policy decisions have been reached regarding pricing and taxation policies for the petroleum sub sector. The policy statement includes a schedule (if required) for the implementation of the steps that may be required by these policies.
- The Government of the Philippines would assume all of Petron's long term liabilities (more than one year maturity). This would include payments, as required by law, to all personnel that will be discharged as a result of the sale.
- The successful bidder would be allowed to employ his own key personnel, as necessary and to retain only the members of the existing staff deemed necessary for the operation.
- The successful bidder must undertake to either continue operating the existing facilities for a period of at least 10 years, or to replace them with modern equivalent (or better) installations.
- The successful bidder will be granted a period of no more than 6 months, after the signing of the purchase contract, to obtain enough equity and financing and to make a full payment, at that time, for the full amount bid for the properties.

14.4.2 Scenario 2 - Petron is Converted into a Share Company and its Shares are sold in Stock Exchanges

The following assumptions would apply to the scenario:

- Petron would be constituted as a limited liability company and all its shares would be issued and floated to be sold to the public worldwide (unless it can be shown that there would be enough interested investors in the Philippine market).

- Petron would continue being responsible for all its short and long term liabilities.

- Petron would retain an impartial internationally recognized firm to make a diagnosis of its personnel needs, especially in management, to allow it to operate as a fully independent company with full responsibility for management. An estimate of the personnel that would be rendered superfluous by the privatization should be included in the study.

- The Government of the Philippines would be responsible for all payments, as required by law, to all personnel that will be discharged as a result of the diagnostic study.

- Petron must undertake to either continue operating the existing facilities for a period of at least 10 years, or to replace them with modern equivalent (or better) installations.

14.4.3 Scenario 3 - Joint Ownership

- Similar to Scenario 2, except that the Government would retain ownership of 51 % of the equity.

- The government would assume all of Petron's liabilities.

14.4.4 Scenario 4 - Leasing of the Refinery

The following assumptions would apply to the scenario:

- Petron would request international bids for the operation of the refinery for a specified period of time (say 15 years). Petron would continue to operate its terminals, distribution and marketing facilities. (This option, however impractical it be, is similar to the schemes used in the electricity sector).

- The successful bidder (lessee) will be allowed to sell the output of the refinery to suit its own interests. The lessee will be responsible for acquiring the necessary feedstock.

- The lessee must have proven experience in operating similar refineries.

- Guidelines shall be given to specify the degree of maintenance to be the facilities, including the condition it must be left in at the end of the lease. The extent to which the lessee could modify the existing facilities should also be stated and guidelines be provided to establish how the cost of these additional investments will be shared between the lessee and Petron.

- The lessee would be allowed to employ his own key personnel, as necessary and to retain only the members of the existing refinery staff deemed necessary for the operation.

- The Government of the Philippines would be responsible for all payments, as required by law, to all personnel that will be discharged as a result of the lease of the refinery.

14.4.5 Scenario 5 - Petron is NOT Privatized

Within this scenario there are two possibilities that should be reckoned with: whether price and margin controls are to continue or not.

If price controls are to remain, there would not be any changes required in the Petron's organization. However, if prices are to be decontrolled, Petron's organization will have to face competition and may have to reorganize some of its functions to assure the services of personnel trained to deal with the new pricing guidelines.

14.5 Steps to Implement the Above Scenarios

14.5.1 Scenario 1 - Sale to a Private enterprise

A thorough investigation would be required to identify any legal obstacles to the sale and to identify what amendments, if any, are necessary to the existing legislation to carry on the projected privatization. If amended legislation is required, it should be initiated as soon as possible.

The preparation of the bid documentation is the first task of the sale process, after its legality has been established. It would be desirable to contract with international firms, with ample experience in the privatization process, the preparation of the bid documents. These documents could consist of two parts: (i) the description of the technical, commercial and legal processes required for the presentation of bids, and (ii) the preparation of the documentation required to cover the financial aspects of the sale.

Evaluation criteria to select the best bid should be prepared ahead of the receipt of the bids. In order to assure the transparency of the evaluation process, it may be desirable to retain an impartial firm to develop these criteria and also to evaluate the bids. The bid evaluation would be in the form of non-binding recommendations - the representatives of the Government of the Philippines would have the final decision of which bid is more convenient.

The documents to structure the financial aspects may be dispensed with, but there would be a much greater assurance to have more interested parties willing to enter the bidding process if an investment banking advisor were retained to prepare the documentation required to organize the financing of the sale and to obtain bridge financing to expedite the period required to close the sale.

It would also be advisable, but not necessary, to retain experienced appraisers to establish the value of the properties being sold. This precaution, although very costly, would provide a guideline of the value of the properties. However the selling organization should not be surprised if the bid offers are considerably below the appraised values.

14.5.2 Scenario 2 - Petron is Converted into a Share Company

A thorough investigation would be required to identify any legal obstacles to the sale and to identify what amendments, if any, are necessary to the existing legislation to carry on the projected privatization. If amended legislation is required, it should be initiated as soon as possible.

A full description of the policies pertinent to pricing of the product, foreign exchange, taxation of the product and import/export limitations (if any) should be prepared. It would: (i) insure full agreement on the interpretation of the existing policies, (ii) identify forthcoming modifications to the existing policies, and (iii) inform the prospective bidders as to the extent of the constraints that might affect their bid.

A plan should be developed to establish how the shares should be sold and what would be their fair value. Since this is a very specialized undertaking, it probably would be practical to retain investment advisors to design the programs for the sale of the shares and to identify interested underwriters for it.

14.5.3 Scenario 3 - Joint Ownership

The requirements would be very similar to Scenario 2.

14.5.4 Scenario 4 - Leasing of the Refinery

A thorough investigation would be required to identify any legal obstacles to the sale and to identify what amendments, if any, are necessary to the existing legislation to carry on the projected privatization. If amended legislation is required, it should be initiated as soon as possible.

A full description of the policies pertinent to pricing of the product, foreign exchange, taxation of the product and import/export limitations (if any) should be prepared. It would: (i) insure full agreement on the interpretation of the existing policies, (ii) identify forthcoming modifications to the existing policies, and (iii) inform the prospective bidders as to the extent of the constraints that might affect their bid.

The preparation of the bid documentation is the first task of the sale process, after its legality has been established. It would be desirable to contract with international firms, with ample experience in the privatization process, the preparation of the bid documents. These documents could consist of: (i) the description of the technical, commercial, financial and legal processes required for the presentation of bids.

Evaluation criteria to select the best bid should be prepared ahead of the receipt of the bids. In order to assure the transparency of the evaluation process, it may be desirable to retain an impartial firm to develop these criteria and also to evaluate the bids. The bid evaluation would be in the form of non-binding recommendations - the representatives of the Government of the Philippines would have the final decision of which bid is more convenient.

14.5.5 Scenario 5 - Petron is NOT Privatized

The public sector may derive some advantages with this alternative. It does not necessarily follow that these advantages will reflect to the benefit of the consumer or the economy. Some of the advantages to the public sector would be:

- The government would have personnel trained in handling crude oil selection, purchasing, transportation, financing, marketing and distribution of oil products.
- The synergism with other divisions of PNOC might be reduced if Petron were privatized.
- Government would lose the opportunity of seconding career employees to Petron, for training and professional development.
- Government would have direct access to expense data related to oil refining and marketing. These data would be meaningful only if Petron is operated efficiently.
- With its own refinery the government could make rather prompt adjustments in crude selection and/or refinery operation to help alleviate supply/demand imbalances.
- Supply could be arranged for certain areas that other companies may not choose to serve. Similarly, supply could be arranged for areas where competition is insufficient.
- A quicker reaction time would be gained by Petron management if governmental approval of internal management decisions is eliminated.

However, there would be advantages to Petron and the economy if it were privatized. Some of these advantages would be:

- A third privately owned company would most likely increase the competitiveness among refining/marketing companies.
- A risk/reward management approach should result in a more innovative and efficient operation.
- A more flexible salary/wage scale, determined by market forces, may attract a wider slate of potential employees.
- Elimination of forced uneconomic imports or production to meet government demands should result in a more efficient overall industry operation.

14.5.6 Time and Costs for the Privatization Process

Each scenario would have a different set of related times and costs. Some typical times for representative projects are listed below, but there is no assurance that in actual practice they will require more or less time to be completed.

It would not be prudent to pursue any of the above scenarios until their legal status is established. The time that might be consumed depends on the situation and whether legislation is required to amend the existing conditions. Experience has shown that it is not unreasonable to estimate that at least six months should be devoted to finalizing the legal situation.

The preparation of bidding documents may also require at least six months, provided that adequate descriptions of the technical aspects exist beforehand.

The evaluation of bids may require 3 - 4 months.

Award of the contract and financial closing (which include the preparation and signing of the contractual agreements) may take 7 - 12 months.

Since some of the above steps may run concurrently, it could be estimated that the privatization process would require at least one year to be consummated. This estimate assumes that no time must be assigned to settlement of the legal status.

The cost to prepare the documentation to carry out the process could vary considerably, depending on how much input can be provided by the government and its agencies. However, it would not be unreasonable to estimate that costs could easily fluctuate between one quarter and one and a half million US$ dollars.

14.6 Summary And Recommendations

There are several ways the private sector can participate in the oil industry. Usually the main justifications for the privatization of components of the public sector are the desire to obtain increased efficiency and also to obtain hard currency to pay for the national debt.

Privatization should be accompanied by regulation, which is the process that must be set up to protect the interests of both the public and the participants from the private sector. Regulation is not price controls: it is the establishment and enforcement of the rules under which all participants must operate. Effective regulation, by decreasing the risks of the investors, will also decrease the prices to the consumers.

The privatization of Petron may take many forms, the preferred one being the sale of its assets to a private enterprise. This option would require several preliminary steps, including: (i) amendments to the existing legislation; (ii) preparation of the bid documentation that must cover technical, commercial, legal and financial aspects; (iii) the development of evaluation criteria for the bids; (iv) the establishment of acceptable schedules to recognize the timing required to put together the financial aspects of the sale.

Various scenarios can be envisaged for the implementation of the regulatory reform required to ascertain a free market economy for the petroleum refining sub sector: including legal, price control and stabilization issues. A detailed possible scenario, and its components steps, is include in this chapter so as to describe some of the issues that might arise.

15 Implementation of Oil Price Decontrol

The purpose of a "Decontrol Transition Process" is to bring about the change from control to decontrol in a smooth manner. Ideally, the change to decontrol would be made with very little public perception that a change has occurred. It is critically important that decontrol be seen as a process in which everyone works cooperatively to insure that the benefits of decontrol are achieved.

The specific objectives of the Transition Process are:

1. To avoid significant consumer price changes at the time of decontrol. The most appropriate time for decontrol is when crude prices are level or falling and the OPSF balance is level or building.

2. To restructure duties and taxes to remove barriers to product imports and product exports. The current duties and taxes should be replaced with new specific taxes on individual products set to achieve desired consumer prices while maintaining government revenue from oil.

3. To implement a plan to progressively increase the frequency of price changes while prices are still controlled. This will help to accustom the public to more frequent price changes and insure that control and decontrol prices are approximately equal at the date of decontrol.

4. Adjust the relative product prices for gasolines and distillate during the changes of Item 3 above to provide incentives to refiners and importers to meet product demand and encourage efficient refinery performance. Also make margin changes deemed appropriate.

5. Plan for the termination of the OPSF by determining a range for the end balance and a disposition of the balance remaining at the end of controls.

6. Increase competitiveness of the oil refining and marketing sector:

   - loosen import controls
   - reduce crude/product duty differentials
   - remove service station controls.

7. Define the actions needed to assure a competitive oil products market place after decontrol. These should include information requirements from the industry, a business monitoring activity, and organizational roles and responsibilities of government departments and agencies to insure against anti-competitive practices.

8. Development of a plan for setting the specific date and detailed steps for the actual cessation of oil price controls.

15.1 Decontrol Issues

It is recommended that action be taken on the following decontrol issues:

Restructure Duties and Taxes - Action on this item is essential in the decontrol process. OPSF adjustments have become an element of the current tax system, shifting tax burden between products. Decontrol without restructuring taxes would result in significant changes to consumer prices that were not in keeping with stated government energy and social policies. Specifically, it is recommended that all import duties on crude oil be eliminated. Duties should be eliminated on those oil products where imports are an important part of supply (specifically diesel, LPG, and heavy fuel oil should be included in this category). A small duty could be retained on gasoline, naphtha, jet fuel, but should not be more than 3%. The added product transportation cost of imported product already affords some competitive protection to domestic refiners and should be considered in setting possible product duties. The 1 *P/L* special duty should be eliminated.

At the time when all the above duties and taxes are eliminated, they should be replaced with specific taxes on each individual oil product. The specific tax level are described in the next section of this chapter. For the most part, the new specific taxes are set so that if decontrol occurred immediately the decontrol price would be approximately the same as the current controlled price. However, a modestly higher tax is recommended for the middle distillates to modestly diminish the price difference between gasolines and distillates.

	Specific Taxes (*P/L*)		
	Premium Gasoline	Diesel	Difference
Existing Specific Taxes	2.52	0.45	2.07
Specific Tax - Based on Current Price	6.00	1.80	4.20
Recommended Specific Taxes	5.85	2.25	3.60

It is important to restructure duties and taxes as soon as possible. The changes will have benefits in alleviating the oil product supply problem and those benefits occur under control or decontrol. It is recommended that DOE should quickly develop a policy paper describing the rationale and benefits of duty and tax restructuring and defining the specific changes recommended and then seek legislative sponsorship to convert the policy recommendations into a legislative proposal. In the following section, it has been assumed that these changes would occur by the beginning of 1994, if it can be done more quickly it would be desirable.

Product Import/Exports - Deregulation of product importation is recommended as another of the steps to improve the supply of oil products, especially middle distillates. This could be done separately or along with the duty and tax restructuring. If it is done before tax and duties are restructured, ERB could consider two tier pricing of distillate product or a change in the current DOCT calculation process to induce more distillate importation by improved pricing.

Price Control and OPSF - In an ironic way, the ERB which has been charged with the responsibility of controlling oil product prices, can have a very important role in implementing decontrol and diminishing the potential problems of the transition. This is made even more important by the need to solve the "Diesel Dilemma" (Chapter 6) while simultaneously decontroling oil product.

It is recommended that the refinery gate price of distillates relative to premium gasoline, be increased by the transportation cost to deliver light product from Singapore to the Philippines (approximately 0.80 - 1.00 $/Bbl or .13 - .16 *P/L*). This charge along with the specific taxes recommended will determine the relative consumer price of gasoline and distillate at the time of decontrol. It represents a realignment of the relative prices of the products compared to current consumer prices; these prices can be realigned over 3 to 5 pricing changes to soften public action. It can be done by dropping diesel prices less on downward price adjustments and raising it more on upward price adjustments.

The OPSF balance should be maintained within a minimum to maximum value range during the transition period. There is a proposed legislative bill (House Bill No.247) that would require OPSF be maintained within a minimum to maximum range and institute an automatic price change procedure. During a visit in March, the K&M team did discuss House Bill 247 with DOE staff. The following points of concern in the proposed Bill were noted:

> "(1) Whenever the OPSF cash balance reaches the maximum fund level, the ERB shall, within two (2) months and without prior hearing, adjust the domestic prices of petroleum products by an amount that will put the OPSF level in flow equilibrium plus a maximum of ten percent (10%) of such amount to minimize expected price adjustments. Flow equilibrium shall refer to a condition where the projected contributions to the OPSF are equal to the expected claims over a given period.
>
> (2) Whenever the OPSF cash balance reaches the minimum fund level, the ERB shall, within two (2) months and without prior hearing, adjust the domestic prices of petroleum products by an amount that will put the OPSF level in flow equilibrium plus a maximum of ten percent (10%) of such amount to minimize expected price adjustments."

The comments which K&M made were based on experience with a Min/Max automatic price adjustment model which is illustrated in the next section of this chapter. The first comment was about the phrase "Shall within two months". The view presented suggested that based on the way crude prices rise and fall, that the price change would best be made at the beginning of the two month interval rather than at the end. The model which K&M developed employs a month look ahead. It assumes that the draw or build on the fund will be as much next month as it is in the current month, then determines if the min or max level will be violated. If the min or max is passed then an anticipatory correction is made. The other comment was about the overcorrection level" plus or minus "an amount that will put the OPSF level in flow equilibrium plus a maximum of ten percent of such amount". The 10% is much smaller than the "overcorrection amount" used in the model. If limited to a 10% overcorrection and the min or max is reached at the beginning of a crude price rise or decline that may span several months, then an automatic correction could be required every month with the OPSF moving progressively beyond the Min/Max limits. The overcorrections used in the K&M Model can be seen in

Section 15.2 and they are based on the idea that if price change is accelerating (changing more each month) the correction needs to be greater. In addition, the further the balance is above or below the min or max, the greater the overcorrection should be. It is suggested that the model be applied using various crude price change patterns to check out possible "overcorrection" terms for the proposed legislative bill.

During the last 18 to 24 months of the transition period prior to decontrol, it is recommended that the frequency of price changes be increased. This will help to accustom the oil product markets in the Philippines to the increased price movements that will be experienced after decontrol. Secondly, it will assure that control and decontrol product price are approximately equal on the day of decontrol and that the OPSF is approximately in balance (or slightly building). It is recommended that in the last year before decontrol that price changes be made about every three months. These changes could reflect the seasonal variation in product prices, where distillate prices go up and gasoline goes down in the 4th and 1st quarters, and gasolines go up and distillates go down in the 2nd and 3rd quarters. In the last quarter before decontrol an additional price change may have to be made, if the crude market is changing.

A determination on the disposition of the OPSF balance at the end of price controls needs to be reached. It is not recommended that the target for the balance be set at zero at the time of decontrol. This would greatly diminish the flexibility of the ERB to reach the desirable conditions of equal decontrol and control prices and the fund being level or building slightly. In fact, a target of zero balance would almost certainly mean the fund would be drawing down, and after deregulation oil product prices would have to go up. The target range used in the model runs of this study has been in the mid range between the min and max. Thus, an appropriate target range needs to be set, and after all outstanding financial liabilities are met, then the fund balance can be transferred to a previously decided use deemed appropriate and legal. The actions for final disposition should include legislative action as required.

Industry Competitiveness - For the consumer to receive the benefits of price decontrol, the market after decontrol must be free of price collusion and other potential anti-competitive practices by industry participants. It is important that regulations, requirements and responsibilities that will affect the competitive practices of oil industry participants need to be communicated before decontrol takes place.

Existing Philippine legislation and regulations on competitive pricing and practices should be reviewed to determine if they are adequate for assuring that the decontrolled oil industry will function competitively. A concurrent review of the regulation of oil industry competitiveness in other countries could also provide additional perspective. The result of this study would be a position paper recommending any changes deemed necessary. Clearly organizational responsibility within the government for monitoring and enforcing anti-competitive requirements would also be defined.

The information that oil industry participants now are required to provide to the DOE should be reviewed to determine if the necessary volume, cost and price information are being provided to permit monitoring efficiency and competitiveness of the

industry. DOE also needs to review information that they are publishing to prevent disclosure of information that would diminish the competitiveness of the market place. This is a particular concern when there are as few industry participants as there are in the Philippines.

The results of the review process and recommendations on additions or changes to regulatory requirements, information requirements, and organizational responsibility for monitoring and enforcement of competitive practices should be completed by end of 1993.

Refining Margins - Refining margins have been discussed in this report. In terms of a decontrol implementation strategy, the objective is not to have prices increase shortly after prices are decontrolled. This means that if markets will justify a legitimately higher level of margin that the current level which is set by controls, then prices should be adjusted upward while controls are still in place to increase margins to the value they would be expected to attain at the date of decontrol.

Margins in the Asia Pacific market have been comparatively attractive in the past year compared to other world refining areas. Asia has the highest oil product demand growth of any world area and markets have been tight, especially for middle distillates. Market attractiveness can be a very transitory situation, nevertheless, in the recommended implementation case of the next section an increase in the control level of margins of .50$/Bbl was made.

Distribution and Margins

The current procedures used by ERB in reviewing and revising distribution allowances appear appropriate. It is suggested that the present procedures continue until decontrol is implemented.

The procedures for establishing the dealer margins are not documented by ERB. Data is lacking for adequate evaluation of the appropriateness of the allowed margins. It is recommended that, if dealer margins are to be controlled beyond 1994, a study be conducted to determine the appropriate margin allowance. If decontrol of dealer margins are to become effective prior to January 1995, the present procedures should be acceptable.

Timing of Decontrol

Republic Act No. 7638 states "At the end of four (4) years from the affectivity of this Act, the Department shall, upon approval of the President, institute the programs and timetable of deregulation of appropriate energy projects and activities of the energy industry". It is assumed from our discussions in Manila that there is broad agreement that the government of the Philippines is committed to oil price decontrol in 1996. The above statement would appear to allow some latitude in the exact date upon which decontrol will occur.

It is recommended that a three month window be established during which decontrol will occur following the earliest date in 1996 after which decontrol can occur. Thus if conditions are propitious at the beginning date of the three month window then decontrol should take effect on that date, or some part of the three month period would be used to get improved conditions.

15.2 Transition Pricing - Recommended Pricing Strategy

An oil price decontrol decision that sets full decontrol at a future date provides a transition period which should be used to enhance the decontrol process and diminish the problems of decontrol. The approach which controllers use to adjust price in the transition period may need to be different from past approaches and pricing patterns, as the primary goal must be to make the decontrol process successful.

A number of case studies using various pricing approaches have been made to illustrate the impact of alternative pricing approaches and to move in steps to a recommended approach. Three case studies have been made using the Philippines Oil Pricing Model which was developed as part of this study. For the runs described in this section the automatic price adjustment routine has been improved and the Min/Max OPSF limits have been adjusted to approximate those of House Bill 247. These study case are illustrated over a five year period. While the transition period may be for only 3 years, the longer period was used to more graphically illustrate the impact of alternative pricing approaches.

The run series includes the following:

Run 1H	-	Historic Pricing Pattern
	-	Strong Diesel Price Market with Seasonal Price Changes
	-	Specific Product Taxes Only
	-	Higher Local Diesel Prices (X-Taxes) to Attract Imports
Run 2M	-	Relative Market Pricing Pattern (only change to Run 1H)
Run 3F	-	Relative Market Pricing Pattern
	-	Upward Relative Consumer Diesel Price Adjustment
	-	Frequency of Price Adjustment Increased in Control Period
	-	Increase in Refiners Margin

In Run 1H, the taxes and duties are restructured so that there are no duties and the only taxes are specific taxes on individual products. The levels of specific taxes are set so that if prices were decontrolled immediately the decontrol product prices would be approximately equivalent to the control product prices. The specific taxes on premium gasoline and diesel are currently 2.52 *P/L* and 0.45 *P/L* respectively with a difference of 2.07 *P/L*.

As can be seen in Table 15-1, in order to obtain approximately the same consumer price difference and same government revenues, the specific tax would be 6.00 *P/L* for premium gasoline and 1.80 *P/L* for diesel. Thus the difference would be 4.20 vs the current 2.07 specific tax difference. This higher specific price tax differential is a consequence of the historic price adjustment pattern that placed a greater portion of price increase on gasoline vs diesel. Secondly, it is assumed that the average price of diesel on the Singapore market will exceed the premium gasoline price over the study period by about 1.50$/Bbl. Finally it is assumed that the Philippines will need to import diesel, but not gasoline, so an added 1.00$/Bbl (the transportation cost from Singapore) is added to the refining gate price of diesel.

Thus the refinery gate price (or DOCT) in the Philippines for diesel will average about 2.50 $/Bbl more than gasoline. Figure 15-1 shows that, while control and decontrol price for gasoline and diesel start out at about the same level, by the beginning of year 4 the control price for gasoline is 38 centavos above the decontrol price and diesel is 19 centavos below the control price. Given the "diesel dilemma" the historic price adjustment scheme should no longer be used.

Table 15-1

Case 1H: Auto Price Adjustment Mechanism
Specific Product Taxes Only, Historic Price Adjustment Pattern

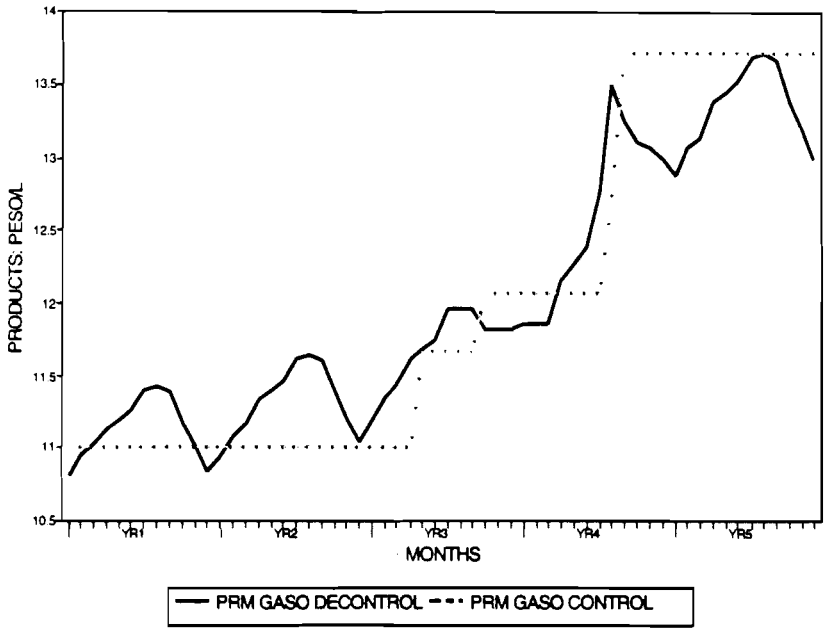
		Specific Tax		Control Prices			Decontrol Prices		
Year & Month	Crude Cost P/L CIF	PRM Gaso	Diesel	PRM Gaso	Diesel	Gaso Diesel	PRM Gaso	Diesel	Gaso Diesel
1-1	2.77	6.00	1.80	11.00	7.00	4.00	10.80	6.83	3.97
3-5	3.38	6.00	1.80	11.67	7.43	4.24	11.66	7.67	4.01
3-10	3.58	6.00	1.80	12.06	7.68	4.38	11.83	8.02	3.81
4-9	4.65	6.00	1.80	12.87	8.07	4.60	13.49	9.50	4.00
4-10	4.49	6.00	1.80	13.71	8.74	4.98	13.25	9.26	4.00

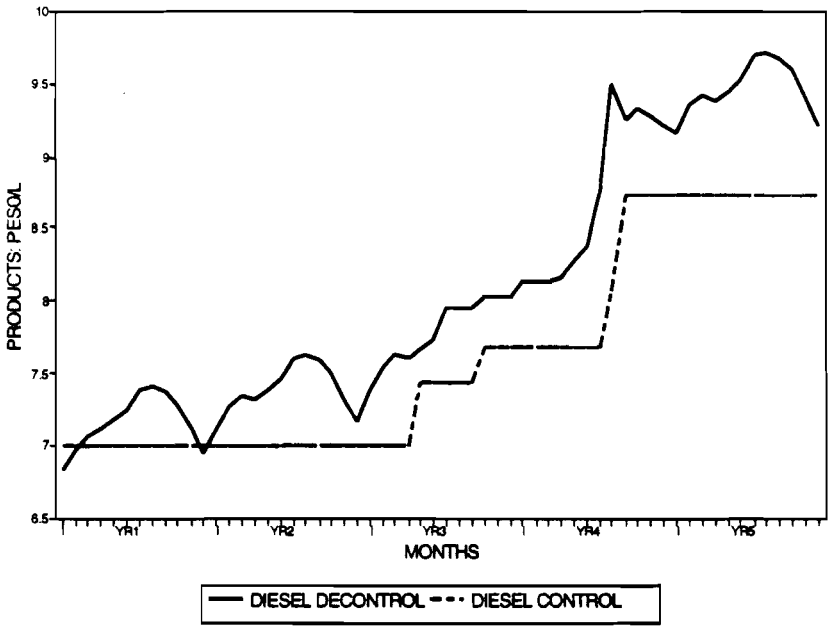
In Run 2M, the only change made compared to Run 1H is that price adjustments are made in relative proportion to the way they change in the Singapore market. The results of this run are shown in the Table 15-2 below and in Figure 15-2. As can be seen in Table 15-2 at the beginning and end of the five year period, the control and decontrol prices are very close - thus the price adjustment process works appropriately. Moveover, if price decontrol were implemented on the first day of year four, the decontrolled price would be fairly close to the control price. The decontrolled premium gasoline price would be 11.86 *P/L* vs the existing control price of 11.91 *P/L* and decontrolled diesel would be 8.13 *P/L* vs 7.91 *P/L*. The decontrolled diesel price is higher than the control price because of the seasonal price swing. The decontrol and control prices are reasonably close at those points in time, as can be seen in the plots of Figure 15-2. However, if decontrol were either six months earlier or later, the disparity between prices would have been much greater. More importantly, the disparity would have been in the wrong direction; that is, the decontrol prices would be higher than the control process because OPSF would be drawn down.

FIGURE 15-1

CONTROL & DECONTROL PRICING CASES

Control With Historic Pricing Patterns



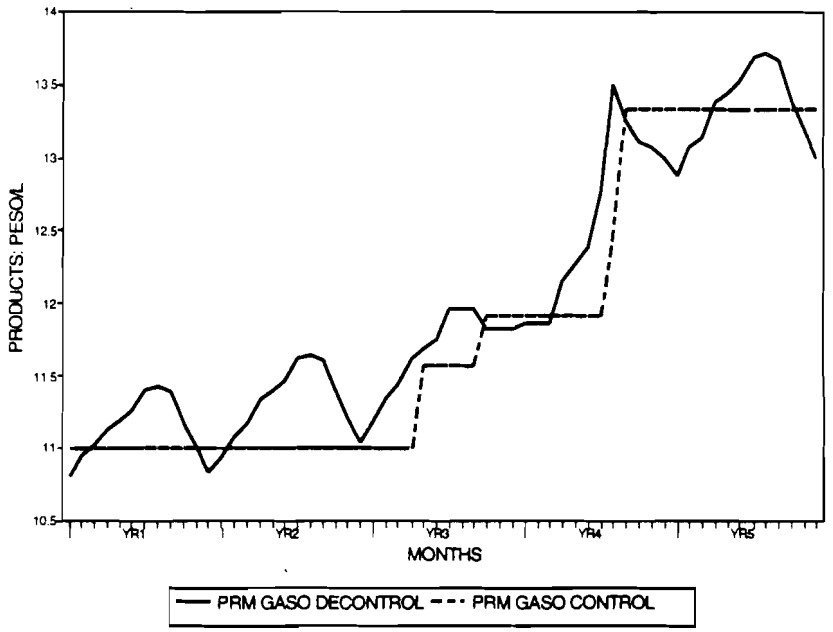


182

FIGURE 15-2

CONTROL & DECONTROL PRICING CASES

Control With Market Pricing Patterns



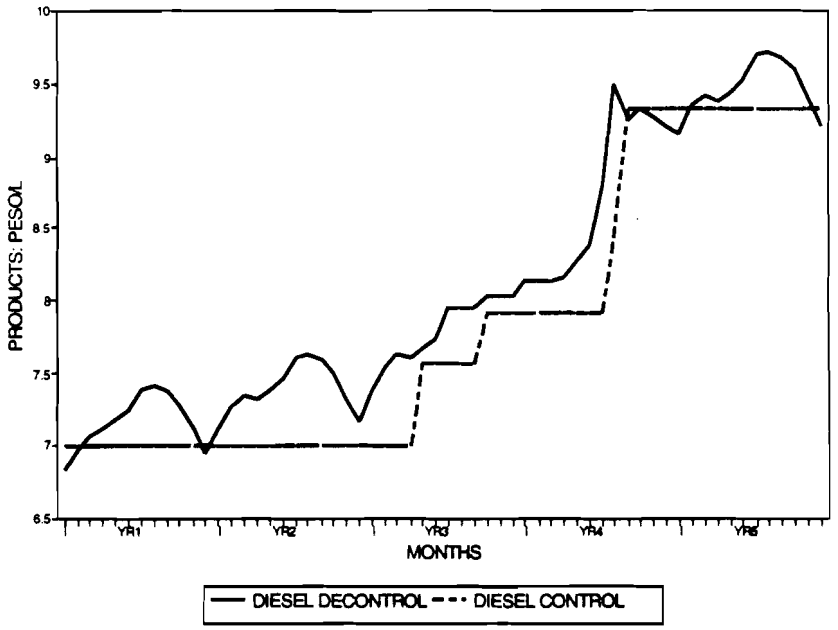


Table 15-2
Case 1H: Auto Price Adjustment Mechanism
Specific Product Taxes Only, Price Adjustment Relative Market Difference

		Specific Tax		Control Prices			Decontrol Prices		
Year & Month	Crude Cost P/L CIF	PRM Gaso	Diesel	PRM Gaso	Diesel	Gaso Diesel	PRM Gaso	Diesel	Gaso Diesel
1-1	2.77	6.00	1.80	11.00	7.00	4.00	10.80	6.83	3.97
3-5	3.38	6.00	1.80	11.57	7.57	4.00	11.68	7.67	4.01
3-10	3.58	6.00	1.80	11.91	7.91	4.00	11.83	8.02	3.81
4-9	4.65	6.00	1.80	12.42	8.42	4.00	13.49	9.50	4.00
4-10	4.49	6.00	1.80	13.32	9.32	4.00	13.25	9.26	4.00

The third run demonstrates the recommended approach to implementation. In actual practice, the timing in some instances does not need to exactly follow what is shown in this run. The run does illustrate how the various steps and changes can be implemented. The following items are dealt with in the run:

Restructure of Duties and Taxes - This should be done as soon as the necessary policy and legislative actions can be carried out. It was done in January 94(Month 1 of Year 2), maintaining total government revenue from duties and taxes at the current level. The tax on diesel is set at a level modestly above that reflected by current market prices to help retard diesel demand growth.

Refiner's Margins - were increased in Month 6 by .50$/Bbl to reflect the currently greater strength of refiners margins in Asian markets compared to other world areas.

Periodic Adjustment of Control Prices - As shown in Table 15-3, price adjustments are made approximately every three months from the middle of year 2 through the end of year 3 when decontrol is assumed to occur. The price adjustments are designed to help adapt the buying public to the more frequent price changes that will occur under decontrol. These price adjustments are also used to make the upward adjustment in diesel price compared to gasoline in several steps. Lastly, in the third year the control prices converge with the decontrol prices (Figure 15-3). Also, an attempt is made to keep the OPSF in even balance or at a slightly rising level at the time of decontrol (Figure 15-4).

Table 15-3
Case 1H: Auto Price Adjustment Mechanism With Forced Periodic Adjustments
Specific Product Taxes Only

Year & Month	Crude Cost P/L CIF	Specific Tax		Control Prices			Decontrol Prices		
		PRM Gaso	Diesel	PRM Gaso	Diesel	Gaso Diesel	PRM Gaso	Diesel	Gaso Diesel
1-1	2.77	6.00	1.80	11.00	7.00	4.00	10.80	6.83	3.97
1-3	2.94	6.00	1.80	10.75	6.90	3.85	11.03	7.06	3.97
1-9	3.16	5.85	1.95	11.00	7.25	3.75	11.36	7.85	3.71
2-6	3.23	5.85	2.25	11.20	7.55	3.65	11.45	8.04	3.41
2-9	3.32	5.85	2.25	11.30	7.90	3.40	11.58	8.17	3.41
3-3	3.30	5.85	2.25	11.45	8.10	3.35	11.42	8.21	3.21
3-7	3.58	5.85	2.25	11.70	8.45	3.25	11.95	8.54	3.41
3-10	3.58	5.85	2.25	11.80	8.61	3.19	11.81	8.61	3.21

The results shown in Table 15-3 and Figures 15-3 and 15-4 show that the changes and objectives which were stated above were achieved in the run. How crude price actually behaves may make this process more different than indicated. Actually, the crude price path illustrated in the sequence of runs is not very favorable for decontrol, as a crude price upsurge occurs in year in which decontrol would occur.

Thus, the public could wrongly assume that the product price increases are the consequence of decontrol rather than a run up in the crude market, over which there is no control.

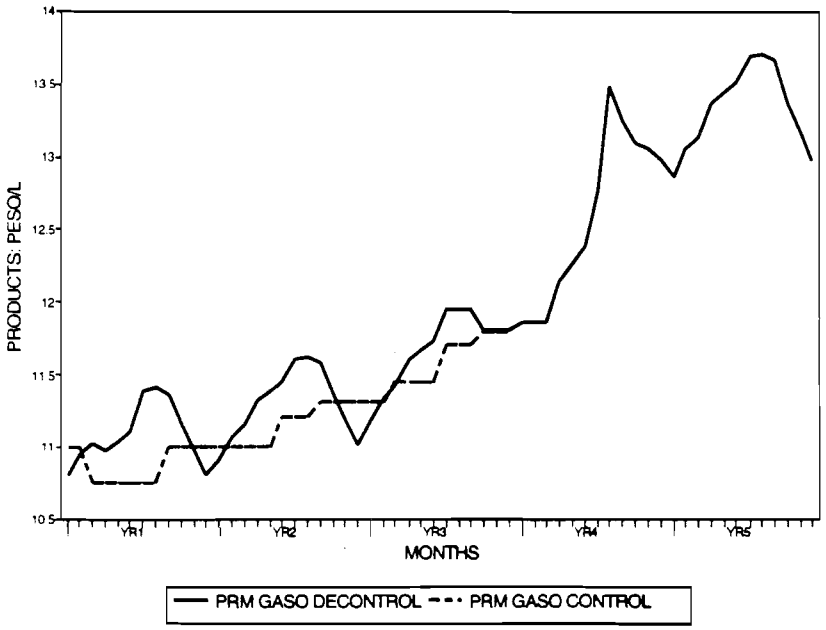
The recommendations made herein constitute a detail strategy for implementing oil product price decontrol in the Philippines. The model used in this study is being provided to the DOE to use in analyzing, anticipating and making adjustment as actual events unfold.

15.3 Decontrol Steps and Timing

In earlier presentations during the course of this study, carrying out decontrol in an 18 month time period was recommended. It now appears that the Philippine government has chosen to decontrol oil prices in a period over 3 years in length. The concern with a longer time period is the delay of the benefits of decontrol and the increased potential of losing the focus of the decontrol process. However, the

FIGURE 15-3

CONTROL & DECONTROL PRICING CASES
Control With Auto & Periodic Man Adj's



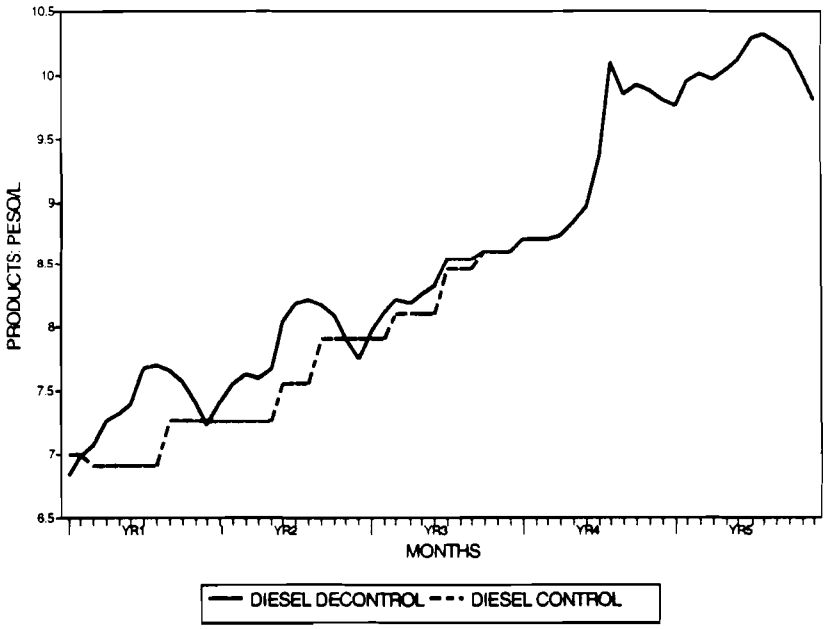
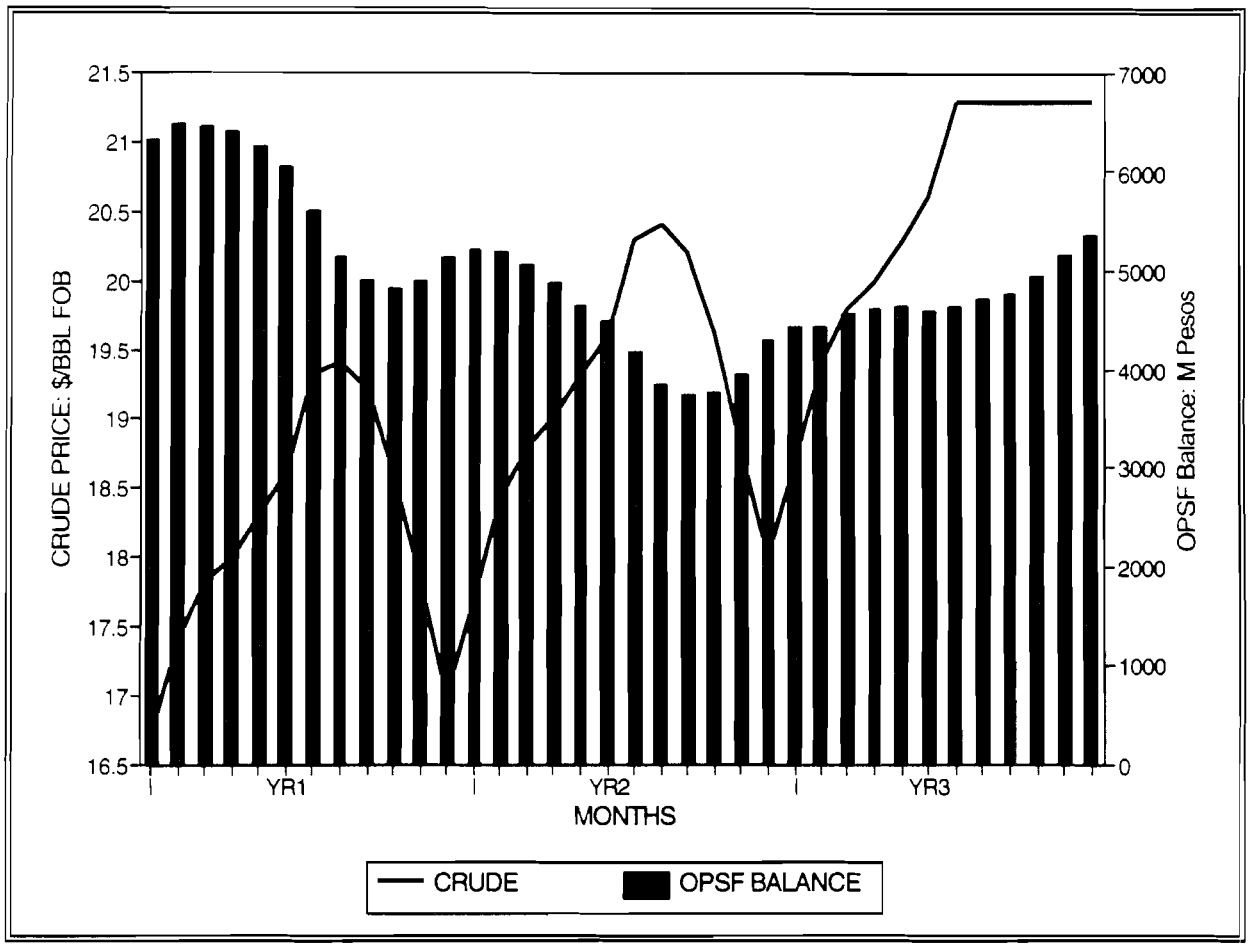


FIGURE 15-4

PHILIPPINE OIL PRICE FORECAST
Control & Decontrol Forecast Cases



longer time frame allows more time to accomplish the many and varied steps which need to be implemented.

The approach to timing of decontrol activities that has been used in this chapter has been to provide a flexible framework that shows the order of priority but allows for some adjustment in timing should events require adjustments. An analytical modeling tool has been provided to do additional analysis and make adjustments to the schedule of action in the decontrol process. Also, as has been indicated, in some areas there are alternative approaches that can be used.

Given that flexibility, there are decontrol activities that need to be done <u>As Soon As Possible</u>. The diesel supply demand problem should be addressed without delay. The second item in Table 15-4 covers the organizational activities needed in the implementation process. Clearly the implementation process need a coordinated effort in which everyone is <u>committed</u> to the objective of making decontrol

successful. ERB's role is especially important since they would be responsible for the implementation of the Phase-In Activities.

Work on the OPSF Min/Max legislation is already in progress. The fund balance and disposition along with the industry competition item should be worked out among DOE and energy regulatory groups along with relevant administrative and legislative activities. All of these items can hopefully be worked out in the next year.

The margin adjustment, the first of the Phase-In activities, can be done as soon as an amount is approved. The Decontrol Day window, if accepted as an approach to setting a specific date, would be implemented in 1996. The last two items in this category would implement phase-in pricing adjustments. The 18-month period is felt to be adequate -- more or less time could be used for this activity. Eighteen months or more is recommended because it gives added time to deal with a potential disruption in crude prices.

15.4 Summary and Recommendations

An effectively planned and managed decontrol transition process that occurs before the actual elimination of oil product price controls can contribute greatly to the success of decontrol. The transition process will require action and committed efforts of DOE and ERB along with the support of other administrative and legislative bodies.

This report recommended that actions need to be taken in a number of areas to bring about the transition, including:

- Responding to the diesel supply/demand problem
- Organizing and coordinating the decontrol transition process
- Planning for the end of OPSF and disposition of the end balance
- Taking needed steps to insure a competitive oil products market place after decontrol
- Implementing "Phase-in" activities to adapt the public to increased frequency of price changes and converging control price into decontrol prices.

The specific steps to accomplish the above items are outlined in Table 15-4. The top items should be taken care of as soon as possible. K&M has recommended an 18 month period for the transition process to achieve the benefits of decontrol as quickly as possible. It would appear that a longer time period is favored in the Philippines, so the transition process has been designed to allow for flexibility in adjusting time frame. It is, however, critically important that the process and effort beginning without delay.

Table 15-4
DECONTROL STEPS AND TIMING

DECONTROL ACTIVITIES	ACTION ITEMS	TIMING
DIESEL DILEMMA	Restructuring of Taxes and Duties	As Soon As Possible (1/94)
	Deregulation of Product Imports	As Soon As Possible (10/93)
	Refinery Gate Pricing Revision	As Soon As Possible (1/94)
	Duties on Diesel Engines/Vehicles	As Soon As Possible (10/93)
ORGANIZATIONAL	Designation of DOE Policy Analysis Responsibility	As Soon As Possible (1/94)
	Decontrol Coordination with ERB, Legislature, etc.	As Soon As Possible
OPSF	Min/Max Price Adjustment Process Implementation	When Bill Effective
	Setting of End Balance Target & Fund Disposition	Policy Position in 6 Months (1/94)
INDUSTRY COMPETITION	Oil Products Marketing Deregulation	When Practical to Implement (1/95)
	Oil Data Submission Requirements	At Least 9 M's Before Decontrol
	Rules & Enforcement for Anti-Competitive Practices	At Least 9 M's Before Decontrol
PHASE-IN TO DECONTROL	Margin Adjustment - Forex Cover & Regional Level	When Resolved as Policy Issue
	Window for Decontrol Day	Next 3-9 Months
	Increased Price Adjustment Frequency	At Least 18 M's Before Decontrol
	Align Control Prices to Decontrol Prices	During Frequent Adjustment Per
	Service Station Decontrol	
	Deregulate Setting Up Retail Stations, Deposits and Refineries	At least 12 Months Before Decontrol
	Petron Privitization	1996

APPENDICES

Report with Recommendations on

COST STRUCTURE AND TRANSFER PRICING FOR THE PHILIPPINE PETROLEUM INDUSTRY

July 9, 1993

Prepared for:

DEPARTMENT OF ENERGY
Republic of the Philippines

Prepared by:

K&M ENGINEERING AND CONSULTING CORPORATION
2001 L Street, NW, Suite 500
Washington, DC 20036

The completion of this report was funded by the United States Agency for International Development (USAID) under a K&M Engineering and Consulting Corporation contract with the Office of Energy and Infrastructure, Bureau for Research and Development Contract No. DHI: 5738-Q-00-1089-00. The views, statements, and opinions contained in this report are the author's alone and are not intended as USAID recommendations, conclusions or statements of USAID policy.

APPENDICES:

APPENDIX A - Philippine Petroleum Pricing Background

APPENDIX B - The Philippine Refining Industry and Oil Products History and Overview

APPENDIX C - Executive Summary

APPENDIX D - Supplementary Figures and Tables

Financial Data on Philippine Oil Companies

Tables

VIII-1 5-Year Financial Performance
VIII-2 Pro forma Operating Earnings, P/Lita, $/bbl
VIII-3 Pro forma Operating Earnings, Pesos and $

Figures

VIII-1 Return on Sales
VIII-2 Return on Assets
VIII-3 Return on Equity

Distribution Costs and Recovery

Tables

IX-1 Caltex
IX-2 Petron
IX-3 Shell

Figures

IX-1 Recovery of Distribution Costs

Other Countries Product Prices and Taxes

XII-3 LPG
XII-4 Regular Gasoline
XII-5 Premium Gasoline
XII-6 Diesel
XII-7 Jet Fuel
XII-8 Kerosene
XII-9 Heavy Fuel

APPENDIX E - Office of Energy and Infrastructure

APPENDIX A:

PHILIPPINE PETROLEUM PRICING BACKGROUND

APPENDIX A

A1 Objectives of the Philippine Petroleum Product Pricing Policy

The existing petroleum product pricing policy has been experiencing much criticism for the past several years. Misconceptions regarding the pricing policy have been the main reasons behind these attacks. It seems that a more transparent price-setting mechanism is needed for petroleum products. For the period beginning 1973 through the first quarter of 1992, the price of imported crude oil (F.O.B.) has been increasing at an average rate of 10.3%, while the retail prices of premium gasoline and diesel fuel have been growing at average rates of 15.8% and 14.7%, respectively (See Table A-1). The divergence in growth rates can be attributed to two factors. The first factor is the rapid depreciation of the peso dollar rate. For the period 1973-1989, the foreign exchange rate depreciated at an annual average of 7.3%. The second factor is relatively faster growth in excise taxes on petroleum products, particularly under an ad valorem tax system.

Table A-1: Prices of crude Oil, Gasoline and Diesel

Year	Crude Oil (US$/bole)	Premium Gasoline (P/liter)	Diesel Fuel (P/liter)
1973	2.48	0.64	0.48
1974	9.31	1.15	0.88
1975	10.68	1.28	0.95
1976	11.52	1.50	1.13
1977	12.39	1.81	1.21
1978	12.56	1.81	1.21
1979	17.02	3.00	1.69
1980	28.82	4.95	2.81
1981	33.98	5.25	3.11
1982	32.81	5.15	3.11
1983	29.08	6.47	4.43
1984	27.98	9.24	7.26
1985	26.78	8.40	6.43
1986	15.37	6.90	4.76
1987	17.05	7.50	5.25
1988	13.71	5.80	3.70
1989	14.96	6.64	4.55
1990	17.84	11.43	7.21
1991	25.63	15.38	6.76
1992	15.87	10.43	6.46

Source: DOE, ERB, CRC-EPRU

The Philippine government seeks to accomplish six major objectives through its petroleum pricing policy. These objectives are the following:

- growth;
- efficiency;
- revenue generation;
- price stability;
- equity; and
- demand management.

It is important to mention that in accomplishing these objectives, trade-offs may occur. For example, a trade-off that should be taken into consideration is the one between revenue generation and price stability. Increasing taxes on petroleum products brings about an immediate increase in government revenues and long-term growth at the expense of short-run growth and price stability.[1]

Below is a detailed discussion of the six major objectives of petroleum pricing policies of the Philippine government.

A1.1 Growth

Petroleum product pricing and its relation to economic development has always been an important issue in that incorrect pricing policies may produce adverse effects on the economy. Poor pricing policies may even instigate protests from the different sectors of society. For instance, overpricing can lead to a cost-push inflation which eventually can dampen domestic demand. However, one benefit that can be derived from such policy is a more efficient utilization of petroleum products. On the other hand, underpricing could increase the country's dependence on imported crude oil and eventually lead to a deterioration of balance of payments (BOP) and balance of trade (BOT) position. Overpricing (underpricing) can be achieved by imposing relatively high (low) excise taxes, import duties and/or profit margins. Petroleum prices should be set in such a way that it would not only stimulate economic growth but also employment. The instrument of energy policy to do this is the excise tax and import duty structure.

The inflationary effects of increases in petroleum prices are widely known. By simply looking at the Input-Output table one can readily notice the importance of different petroleum products to certain sectors of the economy. Petroleum products are intensively used in such industries as cement, construction and electricity generation. In the case of petroleum-intensive and export-intensive industries, an increase in petroleum prices may lead to a loss of price competitiveness.

It is not surprising that a high correlation between peso crude oil price increases and domestic inflation exists. The correlation coefficient of CPI and peso crude oil price is 0.844. The following table shows that the relative movements of these variables follow basically similar paths.

---

[1]Leander Alejo, Energy Demand Management Policies in the Philippines, Asian Development Bank: 1986, p. 68.

Growth Rates in CPI and Domestic Crude Oil Price

Period	Consumer Price Index	Domestic Crude Oil Price
1970 - 1973	53.54	82.77
1974 - 1979	61.62	100.54
1980 - 1991	323.33	126.00

A1.2 **Efficiency**

The government, if it intervenes in the price determination of petroleum products, should make sure that the prices set are reflective of the true marginal cost to society. Otherwise, inefficiencies and interfuel substitution may adversely affect refinery balances. If prices are reflective of the true marginal cost, a more efficient allocation of resources is achieved.

Marginal cost means the cost of producing one unit more or the cost saved by producing one unit less. The concept of marginal cost is related to the principle of opportunity cost. If a certain good or service is priced above the marginal cost, there would be an opportunity cost, as far as the resources not employed to produce that good, since under a marginal cost pricing scheme the demand for that good or service would be greater given its lower price. Conversely, if a certain good or service is priced below its marginal cost, an opportunity cost would be incurred in terms of the additional resources employed to produce that good since the demand would be less.

A1.3 **Revenue Generation**

The taxes on petroleum products seek to achieve four related objectives. These are revenue generation, equity, conservation and price stability. For the past several years, the Philippine government has been very dependent on the petroleum industry for its tax revenues. Statistics show that taxes on petroleum products account for over 10% of the total tax collections and over 45% of excise tax collections of the Bureau of Internal Revenue (BIR) (See Table A-2). In the latter part of 1989, the government decided to adopt a purely specific tax system on petroleum products. The shift from an ad valorem tax system resulted in tax revenue losses of around P10 billion.

Table A-2: Petroleum Product Tax Collections
(in million pesos)

Year	Petroleum Tax Collections	Excise Tax Collections	Total BIR Collections	%share of Petroleum to Excise Tax	%share of Petroleum to Total BIR
1984	5,286	11,432	50,118	46.2%	10.5%
1985	7,390	14,027	61,253	52.7%	12.1%
1986	8,513	16,386	65,491	52.0%	13.0%
1987	11,909	22,641	85,923	52.6%	13.9%
1988	9,735	19,597	90,352	49.7%	10.8%
1989	11,661	24,904	122,500	46.8%	9.5%
1990	13,503	28,899	151,700	46.7%	8.9%

Source: Bureau of Internal Revenue

To achieve the price stability objective, taxes should be imposed in a counter-cyclical manner.[2] This requires that taxes be raised when imported crude oil price declines and in turn be reduced in times of large crude oil price increases. The price stability objective is better achieved under an ad valorem tax system rather than a specific tax system. Being a tax based on value, the excise tax per liter automatically adjusts to any increases in the direct oil company take.

The equity and conservation objectives of taxation will be discussed in the Equity and Demand Management part of this appendix.

A1.4 Stability.

Stability is used here to refer to two things, namely, external and internal stability. External stability is concerned with both the country's balance of payments (BOP) and balance of trade (BOT) position. Internal price stability pertains to reducing fluctuations in petroleum prices to avoid adverse effects on the economy.

The government attempts to achieve internal stability through its Oil Price Stabilization Fund (OPSF). The OPSF is a trust account designed to stabilize petroleum products' prices in the face of fluctuations in crude oil prices in the world market and peso-dollar exchange rate adjustments. The task of the OPSF is to protect the consumers and the economy from the disruptive effects of frequent fluctuations in petroleum products' prices.[3] The mechanics of the stabilization fund will be discussed in the OPSF part of this appendix.

---

[2]Ponciano S. Intal and Clelito F. Habito, Some Observations on Petroleum Pricing and Taxation Policy in the Philippines, Paper presented at the Silver Anniversary of the Philippine Economics Society at the Manila Hotel last December 10, 1987, p. 11.

[3]ERB Files, "The OPSF: Questions and Answers", October 1988, Vol. 1 No.1, p. 10.

Regarding external stability, increases in the dollar import price of crude oil have immediate and adverse effects on the country's BOP and BOT. Any increases in crude oil price would result in a deterioration of the country's terms of trade. In order to offset the increase in the price of imported crude oil, export volumes or prices of the country's major export commodities should likewise increase. For the Philippines, such increases in the price of crude have rather strong adverse effects, since it is highly dependent on imported crude oil for its energy needs. This dilemma can be seen in the percentage share of the value of imported crude oil to total merchandise exports which is relatively high. For the period 1970-1991, the percentage share averaged 18.2% (See Table A-3). However, for the last several years the percentage share has been declining. From 1989-1991, the ratio declined by over 9.5%, meaning that the country has minimized its dependence on imported energy, particularly on imported crude oil.

Table A-3: Petroleum of Crude Oil Imports to Total Exports

Year	Crude Oil Imports (FOB $M)	Total Exports (FOB $M)	Percentage Share (%)
1970	103	1090.1	9.45%
1971	127	1186.0	10.71%
1972	134	1229.5	10.90%
1973	166	1596.6	10.40%
1974	577	3143.3	18.36%
1975	710	2459.2	28.87%
1976	801	3633.5	22.04%
1977	859	3914.8	21.94%
1978	907	4732.2	19.17%
1979	1115	6142.0	18.15%
1980	1857	7277.0	25.52%
1981	2081	7946.0	26.19%
1982	1784	7667.0	23.27%
1983	1742	7487.0	23.27%
1984	1472	6070.0	24.25%
1985	1277	5111.0	24.99%
1986	728	5044.0	14.43%
1987	1061	6737.0	15.75%
1988	923	7035.0	13.12%
1989	1112	7821.0	14.22%
1990	1582	8177.0	19.35%
1991	1400	8840.0	15.84%
1992(Aug)	1084	6299.0	17.21%

Another reason why the country is highly vulnerable to fluctuations in the world crude oil market is the inability of the price of the country's major export commodities (copra, coconut oil and logs) to maintain parity with movements in the world crude oil price. For the period 1971-1991, import crude oil price increased an average of 14.6% per year while the price of copra, coconut oil and logs grew by only 2.4%, 0.8%, and 1.6%, respectively (Table A-4).

Moreover, the shares of the three traditional products to total exports have been declining for the past several years. Copra's share, for instance, decreased from a high of 10.0% in 1971 to 0.2% in 1991, while coconut oil's share shrunk to 3.4% in 1991 from its peak of 18.1% in 1978 (Table A-5). Moreover, the country has banned log exportation since 1987. Presently, however, the country was able to deal with this problem by promoting exportation of non-traditional products. In 1991, the country's top four export commodities were garments, electronic products, copra and copper concentrates. Among these four products, only copra is classified as traditional.

Table A-4
Commodities and Petroleum in the World Market (1975 = 100)

Year	Crude Oil	Coconut Copra	Oil	Logs
1971	17.9	73.6	94.3	64.1
1972	19.3	55.0	59.6	63.4
1973	23.2	137.8	130.5	109.6
1974	87.2	258.3	253.9	132.5
1975	100.0	100.0	100.0	100.0
1976	107.9	107.3	106.4	134.2
1977	116.0	157.0	147.1	151.4
1978	117.6	183.5	173.8	154.8
1979	159.4	262.5	250.5	270.2
1980	269.8	177.1	171.5	325.3
1981	318.2	147.8	145.0	243.8
1982	307.2	122.6	118.2	244.9
1983	272.3	193.5	185.8	228.0
1984	262.0	277.0	293.9	254.6
1985	250.7	150.6	150.0	222.6
1986	143.7	77.1	75.5	255.1
1987	159.6	121.1	112.7	373.4
1988	128.8	154.5	140.2	393.4
1989	140.1	135.8	131.4	462.1
1990	167.0	90.1	85.6	134.2
1991	240.0	115.4	109.8	86.6

Table A-5: Philippine Merchandise Exports (Percentage Share to Total Exports)

Year	Total	Copra	Coconut Oil	Logs
1970	1061.7	7.63%	9.23%	22.89%
1971	1136.3	10.03%	9.06%	18.92%
1972	1105.5	9.95%	7.60%	14.83%
1973	1885.5	5.62%	8.11%	16.12%
1974	2725.0	5.14%	13.98%	7.93%
1975	2294.5	7.50%	10.07%	7.28%
1976	2573.6	5.83%	11.62%	5.25%
1977	3150.9	6.38%	13.08%	4.25%
1978	3424.6	3.97%	18.13%	4.23%
1979	4601.0	1.93%	16.13%	3.13%
1980	5788.0	0.81%	9.80%	1.59%
1981	5722.0	0.59%	9.31%	1.33%
1982	5021.0	0.88%	7.99%	1.55%
1983	5005.0	0.08%	10.31%	1.48%
1984	4391.0	0.00%	10.76%	1.63%
1985	4629.0	0.00%	7.50%	0.84%
1986	4842.0	0.35%	6.84%	0.52%
1987	5720.0	0.54%	6.66%	0.00%
1988	7080.0	0.41%	5.76%	0.00%
1989	7821.0	0.32%	4.85%	0.00%
1990	8186.0	0.26%	4.40%	0.00%
1991	8839.0	0.21%	3.38%	0.00%
1992(Jun)	4550.0	0.09%	6.57%	0.00%

Source: CRC AgriFactbook, REI

A1.5 Equity

Prices should be structured in such a way that the impact of increases in petroleum prices to the lower-income groups should be minimized. The study done by META Systems[4] proposes three methods to address the equity objective of petroleum pricing. These are (1) to prescribe certain consumption levels among different income groups, (2) to impose different tax rates on the same product for different groups and (3) to impose different tax rates on different petroleum products. In the case of the Philippines, the government deems the third method to be the most appropriate. The first two taxation methodologies would prove to be extremely costly to implement. It would be very difficult to categorize people into different income groups. The government would encounter difficulties pinpointing groups into the low or high income brackets.

[4]Meta Systems, Philippine Petroleum Product Pricing Study, p. 2-24.

So well aware of the fact that different petroleum products are consumed by distinct groups in society, the government made use of the third methodology to adopt a sort of "socialized pricing" scheme. For example, Liquified Petroleum Gas (LPG) is mainly used as cooking gas in most rural and urban areas, kerosene is used for lighting the rural areas, diesel fuel is primarily used for mass public transport and fuel oil is primarily used for power generation and manufacturing. Hence, LPG, kerosene, fuel oil, diesel, solvents and asphalts are categorized as mass and industrial fuels. On the other hand, there are the "luxury" fuels which include gasoline (used mainly for private cars) and avturbo (used for airplanes). These types of fuels are used by people in the higher socio-economic brackets.

Under the government's "socialized pricing" scheme, mass consumer fuels incur a lower excise tax rate than luxury fuels. Industrial fuel, thinners, and LPG are exempted from excise taxation. Prior to the shift to the specific tax system, a 48% ad valorem tax was imposed on luxury fuels while consumer fuels were taxed at a 24% rate.

Presently, the highest specific tax rates are imposed on premium gasoline and avturbo at P2.52 per liter and P2.38 per liter, respectively. Kerosene and diesel fuel have lower tax rates at P0.50 per liter and P0.48 per liter, respectively. LPG, fuel oil, and thinners are exempted from excise taxation. The higher income groups are made to bear the brunt of the petroleum product tax burden. How the tax system has changed for the past twenty years will be discussed in detail in the Specific Taxation part of this appendix.

A1.6 Demand Management

To address the demand management objective of petroleum pricing policy, attention should be focused on two important aspects, namely, conservation and substitution. Conservation implies that prices should be set in such a way to bring about a prudent use of petroleum products. Substitution, on the other hand, can be accomplished in three ways. The first is a shift from imported to indigenous fuel. The second is a shift from oil to non-oil sources of primary energy. Non-oil sources include coal, geothermal, hydropower, and the non-conventional energy sources (i.e. bagasse and agriwaste). The third is a shift among refined petroleum products (i.e. gasoline to diesel).

The first oil crisis caught the Philippine economy in a relatively weak position. Three conditions explain the economy's vulnerability to an oil price shock. First, imported crude oil accounted for over 92% of the country's primary energy consumption (Table A-6). Moreover, during that time the country's coal, oil and non-conventional resources were largely untapped. Second, at the time of the first oil crisis, the volatile Middle East Region supplied over 95% of the country's crude oil importation (Table A-7). Third, there was no form of coordination among the different institutions and government agencies concerned with energy. Only in 1977 were the previously dispersed energy demand management policies of the country properly coordinated where crude - % of primary energy construction middle east supplies under the Ministry of Energy was created and given the task of overseeing the country's energy policies.

Table A-6: Historical Energy Consumption - Percentage Share to Total

	1973	1978	1982	1986	1988	1989	1990	1991	1992 (August)
INDIGENOUS	7.98%	19.96%	31.65%	44.33%	37.24%	36.08%	34.27%	34.35%	28.73%
I. Conventional	4.76%	5.93%	17.77%	26.95%	23.89%	22.11%	20.92%	21.62%	16.69%
Oil			3.09%	3.06%	1.76%	1.45%	1.28%	0.88%	0.64%
Coal	0.19%	0.99%	1.16%	4.31%	4.42%	3.52%	3.17%	4.83%	3.82%
Hydro	4.57%	4.93%	6.97%	11.12%	9.99%	9.46%	8.67%	7.51%	4.40%
Geothermal		0.01%	6.55%	8.46%	7.72%	7.68%	7.81%	8.40%	7.82%
II. Non-Conventional	3.22%	14.03%	13.88%	17.38%	13.35%	13.97%	13.34%	12.73%	12.05%
Bagasse	3.22%	6.81%	7.70%	4.38%	4.24%	5.16%	4.49%	5.20%	5.30%
Agriwaste		7.22%	6.10%	12.49%	8.62%	8.34%	8.85%	7.23%	6.41%
Others			0.08%	0.51%	0.48%	0.47%	0.27%	0.30%	0.34%
IMPORTED	92.02%	80.04%	68.35%	55.67%	62.76%	63.92%	65.73%	65.65%	71.27%
Oil	92.02%	80.04%	68.35%	53.34%	59.30%	60.88%	63.18%	63.72%	69.24%
Coal				2.33%	3.46%	3.04%	2.55%	7.65%	2.03%
TOTAL (%)	100.00(%)	100.00(%)	100.00 (%)	100.00 (%)	100.00 (%)	100.00 (%)	100.00(%)	100.00 (%)	100.00 (%)

Table A-7: Crude Supply by Country of Origin (Based on Loading Date) Percentage Share to Total

	1992* %	1991 %	1990 %	1989 %	1988 %	1987 %	1986 %	1985 %	1980 %
MIDDLE EAST									
Kuwait	4.16%		8.52%	13.83%	13.7%	25.4%	14.3%	15.7%	13.1%
Saudi Arabia	49.13%	44.07%	32.19%	13.38%	6.3%	16.3%	22.5%	17.2%	38.8%
Iran	11.15%	14.79%	6.10%	20.89%	17.7%	8.2%	12.9%	4.2%	0.0%
Oman			1.18%		7.5%	5.0%	0.0%	0.0%	1.3%
Dubai		11.79%	21.49%	13.70%	12.6%	3.2%	5.5%	5.5%	10.9%
Iraq			4.40%	5.83%	1.8%	2.1%	0.9%	1.7%	0.0%
United Arab Emirates	12.36%	1.23%	1.30%	5.64%	5.6%	2.0%	3.0%	0.0%	1.9%
Qatar	3.00%	5.51%	5.14%	3.14%	3.8%	1.6%	3.5%	0.0%	0.0%
Neutral Zone					2.4%	1.4%	0.0%	2.0%	0.8%
Abu Dhabi					0.0%	0.0%	0.0%	0.0%	0.8%
Sub-Total	79.80%	77.40%	80.33%	76.39%	71.3%	65.2%	62.5%	46.3%	69.6%
OTHER REGIONS									
Malaysia	10.86%	9.24%	9.19%	10.84%	12.7%	12.2%	18.4%	20.4%	5.0%
China	1.11%	4.20%	1.32%	5.35%	5.8%	10.4%	6.2%	15.7%	9.7%

	1992* %	1991 %	1990 %	1989 %	1988 %	1987 %	1986 %	1985 %	1980 %
Brunei	5.21%	5.91%	5.53%	3.06%	2.9%	4.9%	0.9%	1.1%	2.0%
Indonesia	1.48%	1.54%	0.81%		0.0%	2.2%	6.1%	8.6%	8.5%
Australia			0.49%	2.10%	4.4%	2.0%	0.0%	2.8%	0.0%
Mexico					0.0%	0.0%	0.0%	0.0%	0.0%
Pakistan		0.21%	0.36%						
Sub-Total	18.66%	21.09%	17.70%	21.35%	25.8%	31.7%	31.6%	48.5%	25.2%
Total Imports	98.47%	98.49%	98.03%	97.74%	97.1%	96.9%	94.1%	94.8%	94.7%
Philippines	1.53%	1.51%	1.97%	2.26%	2.9%	3.1%	5.9%	5.2%	5.3%
TOTAL	100.00%	100.00%	100.00%	100.00%	100.0%	100.0 %	100.0 %	100.0 %	100.0%

Source: Office of Energy Affairs
* first three quarters

Upon realizing the precarious situation of the Philippine economy, the government decided to take precautionary measures to prevent the situation of the country from deteriorating further. To lessen the impact of the oil crisis, the government embarked on a three-pronged strategy. These strategies were to develop indigenous energy sources to lessen dependence on imported energy, to diversify use of energy resources and to conserve energy through more efficient conversion systems and better management of key energy variables.[5] The first two strategies adopted by the government call for substitution among energy products.

The same three-pronged strategy was used by the government during the second oil crisis. Compared to the 1973 oil crisis, the second oil crisis caught the Philippines in a much worse condition. In 1973 the economy was experiencing an export boom and was registering an average GNP growth of close to 7%. However, when the second oil crisis occurred in 1979, the economy was experiencing a deterioration of the terms of trade, a chronic balance of payments deficit and an increasing foreign debt service.

The government's energy demand management policies fifteen years after the first oil crisis have been a decrease in dependence on imported energy from 92% in 1973 to 71.3% in 1991. In 1991, the Middle East accounted for 79.8% of the country's total oil importations, down from 95.5% in 1973. This was accomplished through government-to-government and long-term contracts with countries like Malaysia, Brunei and Indonesia. Another major achievement of government's demand management policies is the development of other indigenous sources of energy. In 1991, non-conventional and conventional energies except oil accounted for 4.7% and 3.2% of total energy consumption, respectively (Tables A-6 and A-7).

A2 Institutions Involved in the Regulation of the Petroleum Industry

The principal government agency responsible for determining domestic prices of petroleum products is the Energy Regulatory Board (ERB). In the early 1970's, the Oil Industry Commission (OIC), which was created under Republic Act No. 6173, was given the task of regulating the production and marketing of petroleum products. In 1977, the OIC was replaced by the Board of Energy (BOE) by virtue of Presidential Decree No. 1206, which later was amended by Presidential Decree No. 1208. The BOE enjoyed greater jurisdiction since it was empowered to fix the power rates of electric companies. Unlike its predecessors, the Board's powers and functions were no longer limited to petroleum products.

The ERB was created under Executive Order No. 172, dated May 8, 1987 and started its operations on the first of July of the same year. Regarding to the petroleum industry, the Board was given the task of exercising the following powers and functions:[6]

1. when warranted and when the public necessity requires, the Board may regulate the business of importing, exporting, re-exporting, shipping, transporting, processing, refining, marketing and distributing energy resources;

---

[5]Antonio Paderanga and Cayetano Paderanga, Jr., The Oil Industry in the Philippines, December 1987, p. 5.

[6]ERB Files, October 1988, pp. 37-38.

2. to fix and regulate the prices of petroleum products;

3. to fix and regulate the rate schedule or prices of piped gas to be charged by duly franchised gas companies which distribute gas by means of the underground pipe system;

4. to fix and regulate the rates of pipeline concessionaires under the provisions of Republic Act No. 397, as amended, otherwise known as the "Petroleum Act of 1949", as amended by Presidential Decree No. 1700;

5. to regulate the capacities of new refineries or additional capacities of existing refineries and license refineries that may be organized after the issuance of this Executive Order, under such terms and conditions as are consistent with the national interest;

6. whenever the Board has determined that there is a shortage of any petroleum product, or when public interest so requires, it can take any step as it may consider necessary, including the temporary adjustments of the levels of prices of petroleum products and the payment to the Oil Price Stabilization Fund created under Presidential Decree No. 1956 by persons and entities engaged in the petroleum industry if such amounts as may be determined by the Board, which will enable the importer to recover its cost of importation;

7. to perform the regulatory and adjudicatory powers and functions of the abolished Bureau of Energy Utilization under Presidential Decree No. 1206, as amended;

8. to determine, fix and/or prescribe rates or charges pertaining to the hauling of petroleum products formerly exercised by the Land Transportation Commission;

9. to fix and regulate the rates or charges pertinent to shipping or transporting of petroleum products;

10. to fix and regulate the power rates to be charged by electric companies, except electrical cooperatives and the National Power Corporation; and

11. to impose administrative penalties and sanctions for violations of ERB price and rate orders, ERB rules and regulations and other laws enforced and administered by the ERB.

In fixing and regulating the prices of petroleum products, the ERB conducts a review every sixty (60) days. The Board sets prices for a period of two months ahead, based on the average import cost of the entire industry during the preceding two months. For example, the Board will set petroleum product prices for the months of May-June based on the industry average import cost for the months of March-April.

In this review, the direct oil company takes (DOCT) are adjusted in order to maintain the wholesale posted price (WPP). The 60 day review of the Board is consistent with petroleum companies' inventory build-up. Crude oil supplies purchased by the petroleum companies are usually sold as refined petroleum products two months thereafter.

During the review, the Board also discusses petitions for increases in DOCT submitted independently by the three petroleum companies. These requests cover both increases in the landed cost of crude oil and in the operating expenses. In June 1987, the three petroleum

companies filed petitions with the ERB requesting for relief in terms of direct operating costs. The cost relief requested by the three firms amounted to an average rate of P0.1421 per liter. These are cost increases covering the period from 1983 to 1986. However, during one of the public hearings, the ERB decided that priority be given to increases in the landed cost of crude oil. Accordingly, the Board resolved that petitions filed by the three petroleum companies be revised.

Another government agency that plays a crucial role in the petroleum product pricing is the Department of Finance (DOF). For the past several years, the Philippine government has relied heavily on the petroleum industry for taxes to fund economic development projects. Moreover, taxes have become an increasingly larger proportion of the domestic price of most petroleum products.[7]

Likewise playing an important role in the regulation of the petroleum industry is the Office of Energy Affairs (OEA), now DOE. The OEA was reorganized by virtue of Executive Order No. 193 and was placed under the supervision of the Office of the President. The office is primarily responsible for the formulation, planning, monitoring, implementation of, and coordination of policies and programs in the field of energy. Its primary function is to ensure a continuous, adequate and economic supply of energy with the goal of ultimately achieving self-reliance in the country's energy requirements, through intensive exploration and development of indigenous energy resource, and through the judicious conservation and efficient utilization consistent with the country's accelerated economic growth objectives.[8] The OEA replaced the Ministry of Energy, and although it has no direct hand in the determination of petroleum products' prices, it constantly coordinates with ERB.

A3 The Price Build-Up Mechanics

A3.1 Introduction

The process of petroleum product price-setting is a synthesis of prescribed regulatory and review actions by the Energy Regulatory Board (ERB) and the political reviews and negotiations by the Cabinet with recommendation to the President.[9] The ERB performs the task of fixing and regulating the direct oil company take (DOCT), the oil price stabilization Fund (OPSF), the haulers' charge and the dealers' margin. The Cabinet recommends to the President for approval the excise tax rates for the different petroleum products.

Since the petroleum industry was regulated in 1971, pricing of petroleum products has been largely based on the principle of cost recovery and not the regulation of the rate of profit firms were allowed to make (the latter applies to public utilities which are allowed a 12% return on investment).[10] However, cost recovery has been limited to increases in the landed cost of crude oil.

---

[7]Armando Pestano, "Petroleum Product Pricing in the Philippines," Energy Journal, 9, Special South and Southeast Asia Pricing Issue (1988): 2.

[8]Executive Order No. 193, dated June 10, 1987.

[9]Meta Systems, Philippine Petroleum Pricing Study, P. 2-7.

[10]Ibid., p. 2-7.

For the past twenty years, the basic principles guiding petroleum product pricing have remained essentially the same. Most of the administrative changes that took place were in terms of the stabilization measures and the excise tax system adopted by the government.

Petroleum and petroleum products continue to be of strategic importance to the country's economy. Hence, the government closely monitors the petroleum industry. The industry is one of the most heavily regulated industry in the country. The government's intent is to protect and promote the welfare of the local industries and the consuming public. Government protection and promotion would be to assure adequate supply of refined petroleum products, with acceptable quality and sold at reasonable prices.

A3.2 Components of the Petroleum Product Price Build-Up

Presently, the pump price of petroleum products has six main components. These are the direct oil company take (DOCT), special duty, specific tax, oil price stabilization fund (OPSF), haulers' charge, and the dealers' margin. The shares of each component, on the average, in terms of pesos per liter and percentages are listed in Table A-8.

Table A-8: Petroleum Product Prices As of October 14, 1992

	P/liter	%
Direct Oil Company Take	4.3922	72.3%
Special Duty	1.0000	16.5%
Specific Tax	0.5747	9.5%
Oil Price Stabilization Fund	-0.4414	-7.3%
Wholesale Posted Price	5.5255	91.0%
Haulers' Margin	0.0920	1.5%
Dealers' Margin	0.4578	7.5%
Pump Price	6.0753	100.0%

Source: Energy Regulatory Board

A3.2.1 Direct Oil Company Take (DOCT)

Since the petroleum product price build-up began on January 14, 1971, the DOCT has undergone many changes although the concept it represents is basically the same. In the 1970's, it was known as the netback. Later in 1980, its name was changed to industry cost, before eventually being called the direct oil company take (DOCT).

In determining the DOCT, the ERB makes use of the principle of cost recovery. However, cost recovery has been limited to increases in the cost of crude oil importation. Hence, increases in the firm's operating costs are not included in the computation of the DOCT. Only once in the last twenty years were petroleum companies allowed cost relief in operating expense, with the last being a 2.5 centavo per liter partial cost recovery on May 21, 1986. The reason cited by the government for such practice is that it assumed that the rates of return received by the petroleum companies are "reasonable".[11]

Basically, the DOCT can be broken down further into two sub-components, namely, the peso cost of crude oil and the residual to the oil company. The former is determined primarily by the international price of crude oil and the peso-dollar exchange rate, while the latter covers the firm's operating expenses plus a "reasonable" profit margin.

In arriving at the DOCT's for a certain period (for example May/June), the ERB makes use of a three-step procedure. The first step involves the computation of the landed cost of crude oil (P/barrel) for the period March/April. The next step calculates the difference between the landed cost of crude oil for March/April and for the preceding two months (January/February). It is important to keep in mind that the ERB sets petroleum product prices two months ahead based on the landed cost of the previous two months. Under such a system, the government has the option of temporarily maintaining domestic prices by drawing from the OPSF to absorb the effective cost increases.[12]

The third step involves jointly allocating the change in landed cost across the different petroleum products and then aligning it with the Singapore postings (landed Philippines).[13] Domestic petroleum prices are aligned by multiplying Singapore posted prices (SPP) with the ratio of the weighted average of net wholesale posted prices (WPP) and weighted average of the Singapore posted prices.

An example of how the DOCT is computed is presented in the Tables A-9 through A-12.

---

[11]Corazon M. Siddayao, "Asian Petroleum Pricing Policy," Energy Journal 9, Special South and Southeast Asia Pricing Issue (1988): 113.

[12]Pestano, "Petroleum Product Pricing Policy in the Philippines," Energy Journal 9, Special South and Southeast Asia Pricing Issue (1988): 3.

[13]Singaporean postings (landed Philippines) includes freight, insurance, ocean loss, energy and wharfage fees plus a 29% import tariff. Singaporean postings can be monitored either from the Platt's Oilgram or from Reuter's.

Table A-9: Hypothetical Example
How to compute the Landed Cost of Crude Oil Cost per barrel

Crude Oil Cost (US$ FOB)	16.0000
+ Insurance	0.7815
+ Freight	0.0144
Crude Oil Cost (US$ CIF)	16.7959
x Foreign Exchange Rate*	21.6430
Crude Oil Cost (P CIF)	363.5137
+ Ocean Loss (0.5% of CIF)	1.8716
+ Customs Duties (10% of CIF)	36.3514
+ Energy Fee (0.1% of CIF)	0.3635
+ Wharfage Fee (P1.60 per barrel)	1.6000
Landed Cost of Crude Oil	403.6461

* Foreign exchange rate used by the Energy Regulatory Board is the reference rate or benchmark of the Oil Price Stabilization Fund (OPSF).

Table A-10: How to compute the change in Landed Cost of Crude Oil

Step 1: Subtract January/February from March/April landed cost (P/barrel)

Period	Landed Cost
March/April	403.6461
Jan./Feb.	347.7564
Difference	55.7564

Step 2: Convert the difference, expressed in P/barrel (crude oil) to P/liter (crude oil)

$$\frac{P\ 55.8897}{\text{barrel}} * \frac{1\ \text{barrel}}{158.984\ \text{liters}}$$

= P 0.3515

Step 3: Convert the difference, expressed in P/liter (crude oil), to P/liter (petroleum products) by dividing it by 0.95 to account for the 5% refinery fuel and loss.*

P 0.3515 per liter/0.95 = 0.3700

* According to the **PNOC Primer on Oil Prices**, in the refinery process, a portion is used as fuel, while some portions are lost, such as gases that cannot be captured or as sediments that have no further commercial use. Based on past experiences, petroleum companies recover about 95% of the volume of crude charge as saleable products.

Table A-11:
How to allocate the change in Landed Cost of Crude Oil to each product and How to compute the DOCT's for the period May/June

Step 1: Compute the weighted average of the net wholesale posted prices (net of transshipment cost from the refinery to the depot) using the consumption levels of the previous two months as weights

Step 2: Add change in landed cost, in terms of P/liter of the product, to the weighted average of the net wholesale posted prices

Step 3: Compute the weighted average of the Singapore postings (landed Philippines) using the previous two consumption levels as weights

Step 4: Compute the ratio of the weighted average of net wholesale posted prices plus change in landed cost to the weighted average of the Singapore postings

Step 5: The resulting ratio in Step 4 is multiplied by the Singapore postings (landed Philippines) for each product

Step 6: The resulting product in Step 5 is subtracted from the net wholesale posted prices for March/April

Step 7: The resulting difference in Step 6 is added to the DOCT's for the period March/April. The sum is the DOCT's for the period May/June

Table A-12: Allocation of Change in Landed Cost of Crude Oil

	Consumption Levels Mar/Apr (kl)	Net WPP (P/li)	SPP Landed Phil (P/li)	Adj SPP Align to Net WPP (P/li)	Change in Net WPP (P/li)	DOCT as of Mar/Apr (P/li)	DOCT as of May/Jun (P/li)
Premium	1,149,613	2.800	3.499	3.139	0.339	3.140	3.4781
Regular	557,398	2.408	3.078	2.761	0.353	2.765	3.1183
Avturbo	601,436	3.071	4.339	3.893	0.821	3.883	4.7045
Kerosene	424,805	3.127	4.409	3.955	0.829	3.951	4.7793
Diesel	3,044,862	2.670	3.740	3.355	0.684	3.354	4.0382
Fuel Oil	4,975,563	1.711	2.053	1.841	0.131	1.865	1.9961
LPG	510,657	2.726	3.065	2.749	0.024	2.799	2.8029
Asphalts	38,000	2.028	2.408	2.160	0.132	2.163	2.2947
Thinners	54,373	2.644	3.324	2.982	0.338	2.979	3.3165
Weighted Total	11,356,707	2.289	2.964	2.659	0.861	2.627	3.0399

Change in Landed Cost of Crude Oil: P0.3700 per liter
Resulting Ratio in Step 5: 0.897
SPP is Singapore Posted Prices
WPP is Wholesale Posted Prices

A3.2.2 Special Duty

In January 1991, the country's economic managers decided to impose a 9% import levy on all products, including crude oil. This import duty was imposed because of the tight fiscal targets set by the International Monetary Fund. As such, a specific duty of P1.00 per liter was added to the landed cost of crude oil.

A3.2.3 Specific Tax

Excise taxation on petroleum products has experienced many changes over the past eighteen years. From January 19, 1971 to October 19, 1984, a purely specific tax system was imposed on petroleum products. However, during this period, the specific tax rates on petroleum changed thirteen (13) times. The reason cited by the government for such adjustments are the need to fund economic development with petroleum product taxes and the need to restructure the tax system to prevent wasteful petroleum consumption and encourage conservation.

By virtue of Presidential Decree No. 1956, dated October 10, 1984, a combination of a specific and ad valorem tax system was imposed on petroleum and petroleum products. The

government's desire to stabilize prices for a longer period, in the face of exchange rate adjustments, was the main reason behind the shift.

On May 22, 1984, the specific tax rates on petroleum products were subjected to revisions. The tax rates were increased because of the two rounds of price decreases (due to declines in crude oil price) in the first quarter of the same year, which effected substantial losses in the government's tax revenues. The government believed that these foregone revenues could be recovered by increasing the specific tax rates on the different petroleum products.

On July 14, 1987, the excise tax system for petroleum experienced another shift. This time the shift, under Executive Order No. 195, was to a purely ad valorem tax system. The government was convinced that the adoption of such tax system would provide the flexibility of price changes and obviate frequent revisions of the tax rates as a result of fluctuations in crude oil prices.[14] One disadvantage, however, of a purely ad valorem tax system is it has a compounding effect on the pump prices of the different petroleum products. For instance, a ten-centavo increase in the DOCT of gasoline (because of changes in the crude oil price and/or the exchange rate) would bring about a 19.2 centavo increase in its pump price.[15]

Under Executive Order No. 195, gasoline and avturbo would be levied an ad valorem tax rate of 48%, while diesel oil, kerosene, LPG, thinners and solvents had a 24% ad valorem tax rate. Fuel oil, however, would be exempted from excise taxation primarily because of its importance to the industrial sector. In essence, excise taxation on petroleum products follows a "socialized" pricing scheme. Under this scheme, private car owners and airplane users are made to bear the brunt of the tax burden. Such a pricing scheme has been pursued by the government for nearly two decades. This has had adverse effects on the economy as it led to consumption pattern distortions and refinery imbalances.

In November 1990, the government decided that a shift from an ad valorem to a specific tax system was necessary, considering the developments in the world crude market. With the Iraqi invasion of Kuwait, the world price of crude oil skyrocketed from $15 per barrel to over $40 per barrel. Considering that the ad valorem tax system has an escalating effect on pump prices, the shift in the tax system was deemed necessary.

In order to prevent any shortfall in tax revenues, the Executive branch of government proposed a revenue shift. This is extremely important in the light of the tight fiscal deficit targets set by the International Monetary Fund. However, when the bill on the tax shift was finalized by both the Congress and the Senate, it resulted in a revenues loss of more than P10 billion. Refer to Table A-13 for the specific tax rates imposed on petroleum products.

---

[14]Executive Order No. 195, dated June 17, 187, providing for the shift to a purely ad valorem tax system for petroleum products.

[15]Pilipinas Shell Petroleum Corporation, Petroleum Product Pricing and Related Policy Options, Paper presented to the JoinT Senate-House Committee on Oil and Gas on October 21, 1987.

Table A-13: Specific Tax Rates on Petroleum Products As of October 14, 1992

Product	Company Take Per Liter	Amount of Specific Tax Per Liter	Effective Specific Tax Rate on Company Take
Premium Gasoline	6.9750	2.5200	36.13%
Regular Gasoline	6.4771	2.2800	35.20%
Avturbo	6.1472	2.3800	38.72%
Kerosene	6.1472	0.5000	8.13%
Diesel Oil	6.0160	0.4500	7.48%
LPG	6.2875	0.000	0.00%
Asphalts	4.1989	0.5600	13.34%
Thinners	5.9840	0.0000	0.00%
Fuel Oil	3.8802	0.0000	0.00%

Source: Energy Regulatory Board

A3.2.4 **Oil Price Stabilization Fund (OPSF).**

The OPSF was created by Presidential Decree No. 1956 on October 1984. Three years later, its sources and utilization were expanded through Executive Order No. 137. The primary purpose of the OPSF is to provide a buffer fund to minimize fluctuations in the foreign exchange rate and in the international price of crude oil. It is important to note that prior to 1984, it was the Central Bank of the Philippines (CB) that provided crude oil importers with forward foreign exchange services in order to cover any changes in the foreign exchange rate.

The OPSF was not the first price stabilization measure adopted by the Philippine government. In April 1974, the Oil Industry Stabilization Fund (OISF) was established under Section 8(j) of Republic Act No. 6173, as amended. Basically, the OISF was a fixed levy on petroleum products and was to be used to finance energy development and supply stabilization efforts of the government.

In March 1979, the Consumer Price Equalization Fund (CPEF) was created under Letters of Instructions No. 842. The CPEF was created to counteract the excessive fluctuations in the Organization of Petroleum Exporting Countries' (OPEC) crude oil prices. These fluctuations arose because of conflicts among OPEC member countries regarding what price of crude oil to quote in the international market. In order to avoid frequent movements in the petroleum products' prices, the CPEF drew proceeds from the amount added to the selling price of the petroleum products. Moreover, whenever a petroleum company imported crude oil at a higher price than the benchmark set by the Board of Energy (BOE), it could be reimbursed from the CPEF after showing the required proofs.[16] On the other hand, if the petroleum company were

[16]PNOC, Primer on Oil Prices, p. 17.

able to import crude at a price lower than the benchmark, it was required to contribute to the fund. At first, the CPEF was used to absorb only fluctuations in crude oil prices. Later, its functions were broadened to include movements in the peso-dollar rate. In June 1983, the CPEF was abolished and Letters of Instruction No. 842 revoked. The remaining balances in the CPEF were transferred to the General Fund. The stabilization of crude oil prices in the second half of 1983 was the primary reason behind its abolition.

From the time of CPEF's abolition up to the time of the OPSF's creation, no price stabilization measures were instituted by the government. Hence, it is not surprising to find that during the period that prices of petroleum products experienced five upward movements.

How does the OPSF work? Based on the **Primer on Oil Prices** (1987) published by the PNOC, the mechanics of the OPSF are as follows:

(a) Within a sixty day period or whenever so determined by the ERB, it sets an industry average price for crude oil at a certain foreign exchange rate.

(b) On that basis, it determines the maximum proceeds or shares of the petroleum companies from the wholesale posted price of the products.

(c) If crude landed cost is higher than the base price set by the Board, then the differential or increase is recovered by claiming reimbursement from the OPSF, without disturbing the wholesale posted price.

(d) If crude oil cost is lower than the base price, then the differential resulting in over recovery is paid by the petroleum companies to the OPSF.

International crude oil prices and OPSF balance are constantly being monitored by both the ERB and the OEA. In addition, the OPSF is regularly audited by the Commission on Audit (COA).

An example of how ERB computes the OPSF is presented in Table A-14.

The primary objective of a price stabilization fund is to minimize movements in pump prices in the face of fluctuating international crude oil price and foreign exchange rate. However, OPSF has additional functions. The guaranteed exchange rate facilitates the computation of costs on which domestic price adjustments are based.[17] In the absence of this mechanism, the actual cost of refining can only be determined after the crude oil has been processed and the finished products placed on the market. Second, the OPSF prevents the three petroleum firms from sourcing their dollar import requirements from the domestic monetary system. In the absence of the OPSF, the dollar demands of the petroleum industry would have severe repercussions on the country's interest, inflation and foreign exchange rates. This can be achieved through the government's policy of encouraging the three petroleum firms to stretch their crude oil import payments up to 180 days (down from 360 days previously). This policy relieves the pressure on the relatively weak financial system of the Philippines. After 180 days, the OPSF reimburses the industry of the actual peso cost of crude oil import.

---

[17]Pestano, "Petroleum Product Pricing in the Philippines," Energy Journal 9, Special South and Southeast Asia Pricing Issue, p. 3.

Table A-14

	DOCT as of Jun/Jul (P/li)	DOCT as of Aug/Sept (P/li)	Special Duty (P/li)	Specific Tax (P/li)	OPSF (P/li)	WPP (P/li)	Haulers' Charge (P/li)	Dealers' Margin (P/li)	Pump Price (P/li)
Premium Gasoline	5.5159	5.1470	1.0000	2.5200	1.7626	10.4296	0.0920	0.4748	11.00
Regular Gasoline	4.9697	4.6491	1.0000	2.2800	2.0175	9.9466	0.0920	0.4554	10.49
Avturbo	5.5075	5.1472	1.0000	2.3800	4.8711	13.3983			
Kerosene	5.5429	5.1472	1.0000	0.5000	-0.1746	6.4726	0.0920	0.4307	7.00
Diesel	5.5841	5.0160	1.0000	0.4500	-0.0094	6.4566	0.0920	0.4504	7.00
Fuel Oil	3.1985	2.8802	1.0000	0.0000	-1.2284	2.6518			
LPG	5.4001	5.2875	1.0000	0.0000	-1.0324	5.2551			
Asphalts	3.5172	3.1989	1.0000	0.5600	4.4861	9.2450			
Thinners	5.3520	4.9840	1.0000	0.0000	7.0299	13.0139			
Average	4.6929	4.2722	1.0000	0.5747	-0.1764	5.6705			

217

A third important function of the OPSF is that it ensures (in a way) the viability of the petroleum industry. When the landed cost of crude oil is higher than benchmark set by the ERB, the OPSF is used to reimburse to the industry the peso cost difference.

A3.2.5 **Haulers' Charge**

This is the amount awarded by the ERB for the inland transport services, usually by tank trucks, for the petroleum products. This charge is based on the petitions submitted by the Petroleum Haulers Association to the Board. Haulers' charges are limited to the retailed products, such as gasoline, kerosene and diesel fuel oil. Presently, the haulers' charge stands at 9.20 centavos per liter for the four retailed products.

A3.2.6 Dealers' Margin

Like the haulers' charge, the dealers' margin is awarded by the ERB. These margins are based on the petitions submitted by the Philippine Petroleum Dealers Association. In some cases, the hauler and the dealer are one and the same, hence both fees go only to one person. Presently, the dealers' margins are 47.46, 45.54, 43.07 and, 45.04 centavos per liter for premium gasoline, regular gasoline, kerosene, and diesel fuel oil, respectively.

A4 Factors Considered When Changing Petroleum Product Prices

There are many factors considered by the government when undertaking changes in petroleum product prices. However, it seems that the heaviest weight is given to the socio-economic and political factors. This is largely due to the fact that any increases in petroleum product prices would automatically raise the prices of basic goods and services. Moreover, the hardest hit of any such increases in the prices of basic commodities are those belonging to the lower income brackets. In short, the government is very much concerned about the inflationary effects of any upward movements in petroleum product prices on the poor.

The depletion or the build-up of the OPSF is normally the signal for changes in petroleum product prices to take effect. This, however, is rarely an automatic mechanism. The average price of crude may have gone down, but this does not automatically translate into a petroleum price rollback.

The process of effecting changes in petroleum product prices begins with the petroleum companies' submission of petitions for price adjustments. These petitions are submitted independently by the three firms. What usually triggers requests for price adjustments are movements in price of crude oil and the peso-dollar rate.

Conversely, when the average price of crude oil is lower than the benchmark set by the ERB, it means that the OPSF is being built-up. The reason is that the cost differential between the actual crude oil price and ERB's benchmark is deposited by the petroleum companies in the OPSF. Once this reaches a certain level, a petroleum price roll back may be implemented by the government. It is important note again that this is not automatic.

An appreciation or depreciation of the peso-dollar exchange rate has basically similar effects on the OPSF and the wholesale posted price as the movements of the average crude oil price. The absolute level of change may, however, be different.

Petitions submitted by the three petroleum companies included both increases in landed cost of crude oil and operating costs. All three firms have pending petitions with the ERB regarding recovery of direct operating expenses.

Petron generally has the lowest price adjustment request among the three firms in the industry. There are three reasons why Petron's petitions are such. First, the majority of Petron's sales are in terms of the black products (e.g. fuel oil), which are cheaper to produce. In 1988, fuel oil accounted for over 50% of Petron's total sales volume. Petron has the lowest refining cost in the whole industry. Second, Petron has the largest sales volume in the entire industry, which means it can spread its costs over a much larger base. Petron's manufacturing costs are the lowest in the industry despite of its capacity utilization rate being below 75%. The firm is able to realize a lower average cost per unit relative to the two privately-owned firms. Third, Petron normally incurs little marketing expense when soliciting government accounts. Due to Petron's refinery configuration, it accounts for 70% of NPC requirements, which alone represents close to 15% of the entire petroleum market.

When all of the petitions have been submitted, the ERB reviews the requests and supporting (papers) document action submitted by the three petroleum firms. In addition, the Board conducts public hearings to solicit valuable inputs from other sectors of society. Once all reviews and hearings have been conducted, the Board sets an average rate of increase/decrease in the DOCT. More often than not, the average rate of increase/decrease granted by the Board is closest to Petron's petition. In determining the rate of increase/decrease, the Board basically follows an incremental cost plus pricing approach (See Table A-15).[18]

[18]Leander Alejo, Energy Demand Management Policies in the Philippines, p. 73.

Table A-15: Landed Cost of Crude Oil Direct Oil Company Take Wholesale Posted Price (Pesos per Liter)

DATE	Landed Cost	DOCT	WPP
08-15-87	2.8890	3.3270	5.0830
08-26-87	2.8890	3.2072	4.6210
05-03-88	2.4097	2.8050	4.3569
08-18-88	2.4041	2.7397	4.1025
11-08-88	1.8593	2.2238	3.3852
01-01-89	1.9682	2.2874	3.2771
03-01-89	2.1874	2.6273	3.2677
05-01-89	2.5781	3.1012	3.3289
07-01-89	2.6001	3.0405	3.2357
08-16-89	2.6001	3.0705	3.4895
09-01-89	2.5559	3.0349	3.5171
11-01-89	2.6369	3.1803	3.5665
11-30-89	2.6369	3.1803	4.4790
01-01-90	2.7666	3.3468	4.4862
03-01-90	2.9625	3.5546	4.5090
05-01-90	2.7585	3.3204	4.4547
07-01-90	2.5480	3.0752	4.4329
09-01-90	3.0404	3.6400	4.4866
09-21-90	3.0404	3.6400	5.9026
10-05-90	3.0404	3.6400	5.9026
11-01-90	5.5500	6.2384	5.8529
12-05-90	5.5500	6.8225	8.8790
12-08-90	5.5500	6.8225	8.8840
12-10-90	5.5500	6.8225	8.1152
01-01-91	6.0761	6.8421	7.7280
03-01-91	4.3944	5.0386	7.5052
05-01-91	3.6158	4.3102	7.6439
07-01-91	3.6514	4.3305	7.6149
08-14-91	3.6514	4.3305	6.4489
09-01-91	3.6788	4.3861	6.4884
09-27-91	3.6788	5.3861	6.4884
11-01-91	3.9928	5.7588	6.5341
12-20-91	3.9928	5.7588	6.3041
01-01-92	3.8142	5.5340	6.2891
03-01-92	3.4903	5.2012	6.2460
04-14-92	3.4903	5.2041	5.9787
05-01-92	3.5313	5.3131	5.8152
07-01-92	3.9585	5.6926	5.6726
09-01-92	3.5723	5.2722	5.6705
10-14-92	3.5723	4.3922	5.5255

Source: Energy Regulatory Board

After the average rate of increase/decrease has been determined, it is allocated across the different petroleum products based on the existing ratios among the Singapore posted prices.

The last step is the determination of the OPSF impost on the different petroleum products. The OPSF impost set by the ERB is based on the OPSF level the government wishes to maintain and how quickly the OPSF deficit (if any) should be reversed. According to ERB Commissioner Atty. Mario Lacqui, there is a need to maintain a reasonable fund level of at least P500 million[19] At such a level, the OPSF can absorb a $2.00 per barrel (CIF) increase in crude oil price or a P4/$ increase in the peso-dollar rate, without the fund registering a negative balance.

A5 Implications of Government Pricing Regulations on the Petroleum Industry

Since the creation of the Oil Industry Commission (OIC) in 1971, the structure, conduct and performance of the Philippine petroleum industry has experienced numerous changes. For instance, the number of refineries in the industry has been reduced from four in 1970 to three presently. Moreover, gone are the days when there were firms engaged purely in the marketing of refined petroleum products. Many of these changes may have taken place because of the numerous regulations affecting the petroleum industry. On the other hand, these changes may have been partially due to the two oil crises that affected the whole world in the 1970's. During this period, the international price of crude oil increased more than ten-fold. In this appendix, the implications of the existing pricing regulations on the Philippine petroleum industry will be discussed. To do so, the viability of the industry is analyzed and examined.

The primary reason why the government decided to regulate the petroleum industry is the strategic value of its product to the country's industrial sector. In addition, refined petroleum is an essential input to the domestic power generation plants. This position of the government is stated in Republic Act No. 6173, more commonly known as the Oil Industry Commission Act, dated April 30, 1971. The above-mentioned regulation declared the national policy on the petroleum industry in recognition of the fact that "petroleum and its products are vital to national security." Hence, by introducing such types of regulations into the industry, the country would be assured of an adequate and continuous supply of refined petroleum products. In addition, R.A. No. 6173 states that these products would be sold at reasonable prices and its quality would be consistent with accepted industry standards.

It is important to note, however, that government pricing regulations should be set in such a way that the viability of the domestic petroleum industry is maintained and enhanced. In order to achieve this, the government must assure the domestic petroleum companies that the followings conditions exist:[20]

- Timely recovery of increases in crude oil costs and effect of exchange rate changes on such crude costs;
- Prompt and adequate relief from increases in refining, distribution, marketing and financial costs incurred in the process of making the required products available to meet market requirements;

---

[19]Manila Bulletin. "Oil firms allowed to draw P8 million daily." April 11, 1989. p. 25.

[20]Pilipinas Shell. Petroleum Product Pricing and Related Policy Options. p. 2.

- A fair and reasonable return on the business consistent with the magnitude of the assets and resources required and the risks involved.

A5.1 Timely Recovery of Crude Oil Costs

Petroleum products' prices are reviewed by the Energy Regulatory Board (ERB) on a bi-monthly basis. Moreover, prices are set on the basis of the previous two months actual crude oil import costs. This means, for example, that petroleum prices for the months of October and November are set based on the crude oil import cost incurred in the months of August and September. The 60-day review practiced by the ERB is consistent with the inventory build-up of the three petroleum companies. Normally, these firms are able to sell the refined petroleum products two months after the crude oil has been purchased.

Together with the OPSF, such practice by the ERB has several advantages. For one, it minimizes the effects of movements in the international price of crude oil and peso-dollar exchanges rates on domestic petroleum product prices. Second, as mentioned earlier, the guaranteed exchange rate of the OPSF scheme facilitates the computation of costs on which domestic price adjustments are based.[21]

Essentially, full recovery of crude oil cost is not a problem since the existing price-setting mechanism guarantees such a recovery. Moreover, the OPSF is there to reimburse the petroleum companies of the cost of crude oil imports incurred over and above the benchmark set by the ERB. On the other hand, if crude oil cost is below the benchmark, firms have to contribute in the OPSF's build-up. It is important to note, however, that the cost of crude oil used is based on an industry average and does not differ from firm to firm. In addition, every crude oil importation is reported to and carefully monitored by the ERB and the Office of Energy Affairs (OEA). This is to make sure that the petroleum companies obtain the most competitive terms from their international crude oil suppliers.

The problem, as far the recovery of crude oil cost is concerned, is in terms of timing. The Commission on Audit (COA) strictly scrutinizes the claims submitted by the three petroleum companies and it sometimes takes about five months to process and verify the claims made.[22] Such a delay is expected to severely affect the cash position of any of the three petroleum companies. When the OPSF is in a deficit, this problem is expected to worsen since no reimbursement is forthcoming.

How do delays in OPSF reimbursements affect the petroleum companies? Delays in the reimbursements greatly affect the firm's ability to service its financial charges. In order to analyze this problem, the monthly cash flows of the petroleum companies should be examined. Normally, a petroleum firm maintains a monthly cash flow level of P2.0 billion, P1 billion of which is used to cover the firm's monthly crude oil importation.[23] While the remaining P500 million is used to finance operating expenses (such as refining and marketing costs) and specific taxes. It is important to note that excise taxes for petroleum products are paid in

---

[21]Pestano. "Petroleum Product Pricing in the Philippines." Energy Journal 9. p. 3.

[22]"Oil firms' disbursements cleared." Manila Bulletin. August 24, 189. p. 23.

[23]"The Big Problem in Non-Remittance of OPSF Funds." Business World. July 31, 1989. pp. 1 and 3.

advance, meaning that as soon as the finished products are transported out of the refinery the specific taxes have to be remitted to the government. On the other hand, the sources of cash of the firm are the sales of petroleum products, OPSF reimbursements and the interest earned on money market placements. Again, it is worth mentioning that not all sales by the firms are in terms of cash. Some of its clients (especially the industrial customers) are extended credit lines by the firms.

Based on the figures mentioned above, the petroleum firm tries to maintain a beginning cash balance of at least P2 billion, so that it could meet its short term obligations. Under such case, a ratio of at least one-to-one should be maintained between the firms' sources and uses of cash. Hence, the timing of the OPSF reimbursements is extremely crucial in preserving the ability to cover its short term obligations. Any delays in the reimbursements mean a deterioration of the company's cash flow position and possibility of defaulting payment to suppliers. If such a case happens, then the trade facility with the Overseas Banking Units (OBU) would be canceled and the local petroleum companies would be forced to pay cash for their monthly crude oil imports.[24] However, with the company's relatively weak cash flow position such would be impossible. Eventually, the petroleum company would be compelled to postpone their crude oil importation and this would cause a supply shortfall of petroleum products in the local market.

It is important to note, however, that the problem of crude oil cost recovery arises when the actual cost of crude imports exceeds the benchmark set by the ERB. In this case the wholesale posted price is unable to cover the actual crude or product cost.

Sometimes it takes the COA five months to scrutinize and process the claims of the petroleum companies. In such an event, a large amount of the cost by the industry is left unrecovered. Assuming a daily oil consumption of 225,000 barrels and an average OPSF drawdown of P0.10 per liter, a five month delay would amount to P536.6 million (See Table A-16 for details). This would be equal to an OPSF reimbursement of P178.9 million per petroleum company. Such an amount of money would definitely go far in terms of improving the cash flow position of a given petroleum company.

[24]Ibid., pp. 1 and 3.

Table A-16: OPSF Reimbursements

225,000 *150 days (5 Months)	daily oil consumption
33,750,000 *158.984	oil consumption for five months convert barrels to liters
5,365,710,000 *0.10	average OPSF draw down per liter
536,571,000	total overdue OPSF reimbursements

On the other hand, if the actual cost of crude oil is less than the benchmark set by the ERB, the difference between the two is deposited by the petroleum companies in the OPSF. In such a case, the wholesale posted prices more than cover the actual crude oil cost.

A5.2 Prompt and Adequate Relief From Increases in Operating Cost

Clearly, another major problem plaguing the petroleum industry concerns the profitability of petroleum refining and marketing, which is the industry's core business. This problem has greatly affected the market structure and the business of the three local petroleum companies. Three year ago, Francis Ablan, President of Caltex Phils., Inc., reported that of Caltex's P151 million net earnings after tax in 1988, none came from its so-called core business.[25] In fact, he added that petroleum refining and marketing registered a net loss of P 10 million for the same period.

The main reason why petroleum refining and marketing has been reduced to a relatively break-even venture is ERB's ruling of limiting the petroleum companies' cost recovery to increases in the cost of crude oil. The Board's ruling is based on Letters of Instruction No. 1441, dated November 20, 1984, which states "price adjustments shall cover only increases in crude oil cost and finished product import cost and shall not include any adjustments for operating and other oil company costs."

As of October 14, 1992, the wholesale posted price of local petroleum products can be broken down into the following components:

[25] "Caltex turns around, shows P151M profit." Manila Bulletin. June 14, 1989. p. 26.

Components of Petroleum Product Price as of October 14, 1992

	P/liter	Average Price %
Cost of Crude Oil	3.5723	64.7%
Duty/Wharfage/BOE Fee	0.3483	6.3%
Specific Tax	0.5747	10.4%
OPSF	-0.4414	-8.0%
Residual to Oil Company	1.4716	26.6%
Wholesale Posted Price	5.5255	100.0%

Hence, on the average about 26.6% of the wholesale posted price goes to the petroleum company. On the other hand, the government collects 16.7% of the posted price, in the form of tax revenues. Since 1984, the share of the residual to direct oil company take has been increasing--from a 5.5% in 1984 to 27.2% by 1992 (See Table A-17 for details). It was only during the crisis years of 1983-1885 when the share of the residual to direct oil company take fell below the 10% mark. For the period 1981-1992, the percentage share to DOCT averaged over 13%.

Table A-17: Residual to Oil Company (Pesos per Liter)

Year	Average DOCT	Landed Cost	Residual to Oil Company	Residual as % of WPP	Residual as % of DOCT
1981	2.2331	1.9356	0.2976	2.8625	13.32%
1982	2.1950	1.9607	0.2343	2.9010	10.67%
1983	2.6428	2.4047	0.2380	3.2175	9.00%
1984	4.4444	4.1552	0.2892	5.2650	5.49%
1985	4.7808	4.4214	0.3594	6.1082	6.51%
1986	2.9779	2.5835	0.3943	4.5985	13.24%
1987	3.2079	2.7826	0.4253	4.3859	13.26%
1988	2.6615	2.2702	0.3813	4.1393	14.33%
1989	2.8799	2.4211	0.4587	3.4521	15.93%
1990	3.9024	3.2704	0.6320	5.0273	16.20%
1991	5.1866	4.2836	0.9030	7.2596	17.41%
1992	5.4096	3.6786	1.4716	5.9387	27.20%

Source of basis data: Energy Regulatory Board
Note: Figures listed above are weighted averages, with the number of days of effectivity as weights.

Moreover, it is important to note that the "residual" figure is not all profit for the petroleum firm. This amount must still cover the following costs:[26]

(1) the cost of refining crude oil into the various petroleum products required by the country;

(2) the cost of transporting refined petroleum products to various storage points and depots throughout the country for eventual distribution to the consumer;

(3) marketing and other operating and administrative costs essential to the efficient running of the business;

[26]Pilipinas Shell, Petroleum Product Pricing Policy and Related Policy Options.

(4) a reasonable profit from operations commensurate to the substantial level of assets and capital resources committed to, and the risk in, ensuring the availability and the smooth and continuous flow of petroleum products to the consumers;

(5) financing costs of working capital and fixed capital.

Hence, a large portion of the petroleum company's operating expenses are comprised of maintenance, marketing, and materials costs. Although the above-mentioned operating costs are considered to be direct, uncontrollable and readily verifiable, only once in the past eighteen years had the three petroleum companies been granted a partial recovery in increases in these costs. Presently, the three have pending petitions with the ERB. Refer to Table A-18 for the details of the petitions of the three petroleum companies.

Table A-18a: Summary of Operating Costs 1991 over 1987
Centavos per Liter
CALTEX PHILIPPINES

Refinery Operating Expenses	2.59
Marketing Expenses	7.09
TEL/Chemical/Catalysts	3.29
Net Interest Expense, Financing Cost, Recovery and Risk Free	5.46
Transhipment Underrecovery	1.85
Total Increase 1991 over 1987	20.29
Less:	0.78
Total Underrecovery	19.51

Source: Energy Regulatory Board

Table A-18b: Summary of Operating Costs 1991 over 1986
Centavos per Liter
PETRON CORPORATION

	1986	1991	Underrecovery
MARKETING			
Materials and Supplies	0.38	0.51	0.13
Maintenance and Repair	2.62	2.81	0.19
Purchased Services	0.67	1.79	1.12
Utilities	0.63	0	-0.63
Rentals/Ins/Taxes	1.22	1.49	0.27
Depreciation	0.81	2.35	1.54
Other Expenses	1.31	0.56	-0.75
Revenue Credits	-1.05	-0.31	0.74
Sub-Total	6.59	9.2	2.61
REFINING			
Materials and Supplies	0.89	1.16	0.27
Maintenance and Repair	1.58	2.79	1.21
Purchased Services	0.19	0.31	0.12
Utilities	0.5	0.49	-0.01
Rentals/Ins/Taxes	1.44	0.56	-0.88
Demurrage	0.46	0.48	0.02
Depreciation	0.95	2.94	1.99
Other Expenses	0.14	0.06	-0.08
Sub-Total	6.15	8.79	2.64
TOTAL	12.74	17.99	5.25
Plus: Unrecovered opex increases from 1983 to 1986			5.01
TOTAL UNDERRECOVERY			10.26

Source: Energy Regulatory Board

These figures listed in Table A-18 imply that since 1983 the petroleum industry has been suffering from receiving only a partial cost recovery of its operating cost. Such a predicament would adversely affect the financial position of any firm in any industry.

Considering all of these, the question that comes to mind is why petroleum companies continue to be in the Security and Exchange Commission's (SEC) Top 10 Corporations despite of this terrible handicap. For instance, just last year, Petron, Caltex and Shell ranked 3, 4 and 6 in terms of gross revenues, respectively. To answer this question, it must pointed out that petroleum companies have three sources of income. These are petroleum refining and marketing, sales of lubricants and interest rate arbitrage. Lubricants sales are considered to be extremely attractive, considering the fact that they are free from any form of government regulation, while interest rate arbitrage is an arrangement set by the government to make the petroleum industry more profitable.

How does interest rate arbitrage work? Crude oil suppliers of the three petroleum companies are usually paid 30 days after the crude is loaded. However, the government encourages the firms to stretch payment to as far as 180 days (down from 360 days previously). This payment extension is made possible by the credit line (with no interest for the first 30 days) extended by the international crude oil suppliers to the local petroleum companies plus 150 days borrowing from offshore creditor banks. Moreover, the firm need not worry about any upward movement in the peso-dollar foreign exchange rate, since any peso cost differential of crude oil imports could be reimbursed from the OPSF.

The petroleum refiners pay for their crude oil imports 180 days after shipment but at the exchange rate that prevailed when the crude oil was purchased. In effect, they are insulated from the movements of the peso vis-a-vis the U.S. dollar. Their cash cycle is 100 days. Thus, they have 80 days to place their cash in financial instruments that earn interest. However, they have to pay two types of financing costs. They have to pay the OPSF foreign exchange risk fee currently set by the Department of Finance at 2% of the C.I.F. value of crude oil imports. They also have to pay their offshore creditor banks the interest on the debt they transacted for 150 days (or 180 days minus 30 days crude oil supplier's credit, a standard oil industry practice).

Their placement incomes minus the financing costs (which is the OPSF foreign exchange risk plus the interest expense) is their net financing income or income from arbitrage. From 1989 up to the early 1990's when they could delay their payments by 360 days, their placement income comprised half of their total income. In short, their core business contributed the other half. Today, however, with the cutting of the crude oil import financing period from 360 to 180 days, the oil firms claim that they have lost and are continuing to lose about 7 centavos before tax, or more than P70 million per month. This means that the oil firms' financing costs exceed their placement income, a situation that leads to negative net financing income. And with the current proposal by the Department of Finance to further reduce their crude oil import financing period to 150 days, the oil firms may need to shoulder a one-time average increase of P3 billion in working capital.

Due perhaps to this rather intricate manner of regulation, the OPSF has been the subject of a great deal of controversy. It is suspected of formerly providing enormous profits to the petroleum refiners. While the net financing income of petroleum refiners accounted for half of their total income, this is not currently the case with the reduction of the crude oil import financing period from 360 days to 180 days or even to 150 days. Over the long term, since investments in refinery capacity are discouraged because of the existing government regulation, domestic demand may have to met by expensive imports when refinery capacity

eventually runs out.

Why does the government allow such arrangements to take place? The government deems such an arrangement as important not only in improving the companies' profitability but as far as stabilizing the peso-dollar exchange rate as well. On the assumption that the country's daily crude oil consumption stands at 225,000 barrels and each barrel costs about $15, in the absence of such an arrangement local petroleum companies are expected to source some $500 million dollars from the domestic commercial banking system. This is the amount of money local firms have to pay their crude oil suppliers. A dollar demand from the commercial banking system of this magnitude would bring about a deterioration of the country's gross international reserves and cause an upsurge in inflation, interest and foreign exchange rates.

However, such arrangement has also its share of drawbacks. For one, it provides firms a disincentive for investing in the petroleum industry. Firms would rather put their money in the bank and earn a certain interest rather than investing it in the industry and come out break-even. Second, such an arrangement renders the long-term viability of the industry uncertain. Firms choose to remain in the industry not because of the profitability of its core business but because of the profits reaped from their treasury operations. Another reason for staying in the Philippine petroleum industry is that the facilities have been established and there is an option to sell them.

A5.3 Fair and Reasonable Rate of Return

The three domestic petroleum companies, particularly Caltex and Shell, are suffering from a problem of perception. The two privately owned petroleum companies are perceived not to be supportive of the needs of the consuming public. This is largely due to the notorious reputations multi-nationals have acquired in the past. Moreover, people have a hard time reconciling the fact that petroleum companies continue to complain to the government about price control despite continual presence in the Top 10 Corporations in the Philippines. Hence, there is a need to examine the profitability of petroleum refining and marketing in the Philippines.

If aggregate income figures (includes sales of lubricants and interest rate arbitrage) are used, the financial ratios show that the petroleum industry does not approximate the entire manufacturing sector in terms of profitability (See Table A-19 for details). For instance, in terms of net profit margin for the period 1987-1991, the petroleum industry posted an average of 3.88% compared to the manufacturing sector's 4.72%. However, if return on equity (ROE) is used the opposite case will hold true. The petroleum industry averaged 21.81% as against the manufacturing sector's 15.46% for the same period.

Table A-19: Petroleum Industry vs. Manufacturing Industry

	Petroleum		Manufacturing	
Year	NPM	ROE	NPM	ROE
1991	3.95%	21.11%	4.74%	N.A.
1990	4.35%	21.36%	4.28%	13.59%
1989	3.97%	19.82%	5.40%	17.29%
1988	3.00%	17.30%	5.13%	17.20%
1987	4.14%	29.46%	4.07%	13.76%
Average	3.88%	21.81%	4.72%	15.46%

Source: SEC's Top 1000 Corporations

Another aspect of the petroleum industry that has to be analyzed and compared accordingly with the entire manufacturing sector is growth. Growth, in this case, refers to how well the firm is maintaining its economic position in the general economy.[27] In analyzing the growth aspect, financial ratios were likewise used. To come up with the growth ratios, the latest and previous key financial variables are compared. By doing so, one can come up with the average growth for a particular time frame. In this case, 1991 and 1983 values for gross revenues, net sales and net incomes were compared. These variables were chosen because they are the main determinants of the firm's profitability. Moreover, these are the variables commonly analyzed by businessmen when they want to assess the viability or attractiveness of a certain business venture.

The growth ratios indicate that the petroleum industry again is not at par with the entire manufacturing sector (See Table A-20 for details).

Table A-20: Petroleum Industry vs. Manufacturing Sector Growth Rates (1987-1991)

	Petroleum Industry	Manufacturing
Gross Revenues	21.40%	23.89%
Net Sales	12.79%	24.06%
Net Income	11.50%	28.92%

Source of basic data: SEC's Top 1000 Corporations

[27]J. Fred Weston and Eugene F. Brigham. Managerial Finance. 7th Edition. (The Dryden Press: 1981). p. 146.

The points previously presented show that the existing government pricing policies have not ensured and preserved the viability of the petroleum industry. The three petroleum companies have not been allowed adequate relief from certain operating costs considered to be direct, uncontrollable and readily verifiable. As such, petroleum refining and marketing has been reduced to a relatively break-even venture. Moreover, petroleum companies frequently experience delays in OPSF reimbursements. It sometimes takes up to five months for the COA to process the claims of the three petroleum companies. Such delays greatly affect the firm's monthly cash flow position. If these issues are left unaddressed by the government, some of the firms in the industry may be unable to assure the country of an adequate supply of crude oil. This problem may be even worsened by the current middle distillate shortfall.

Total petroleum refining capacity has hardly grown since 1972. For the period 1972-1992, total refining capacity grew by only 0.16% annually compared to the growth rate of 18% it posted from 1954-1972. Petroleum companies found no need to increase capacity despite the fact the petroleum product consumption has been increasing annually by 3.02% in 1973-1979.

Lately, there has been much talk about the possibility of deregulating the petroleum industry. For instance, Caltex has been clamoring for a deregulation of the industry.[28] The primary reason why deregulation has been a hot issue lately is that petroleum companies want to be assured of reasonable returns if they decide to implement their refinery expansion and modernization plans.

Even though the industry has been in such a predicament for the past several years, the three companies still chose to remain. The primary reason is that lubricants sales and interest rate arbitrage continue to bring the industry considerable amounts of money. However, no one knows how long the government will allow the interest rate arbitrage arrangement to be in place. If this arrangement is abolished, the industry's source of income be limited to lubricant sales, considering that petroleum refining and marketing has hardly been reaping any profits.

---

[28] "Caltex faces default unless OPSF is funded." Manila Bulletin. August 30, 1989. p. 29.

APPENDIX B:

THE PHILIPPINE REFINING INDUSTRY AND OIL PRODUCTS MARKETS HISTORY AND OVERVIEW

B THE PHILIPPINE REFINING INDUSTRY AND OIL PRODUCTS MARKETS HISTORY AND OVERVIEW

B.1 Definition

The Philippine Standard Classification Index (PSIC) defines petroleum refineries as those producing gasoline (motor spirits), fuel oils, illuminating oils, solvents, lubricating products, mineral wax, mineral jelly and other products from crude petroleum and its fractional products.

However, the petroleum industry is not limited to petroleum refining since the marketing activities of the different petroleum companies play a crucial role in the firms' operations. In recognition of the importance of marketing to the industry, the PSIC created a category to include the wholesaling of petroleum products. Hence, the petroleum industry is a combination of petroleum refining and distribution of refined petroleum products.

B.2 Brief History of the Philippine Petroleum Industry[1]

Prior to 1954, foreign companies had established some petroleum distribution outlets in the Philippines. For instance, in 1911, Texas Oil Company set up service units and terminal facilities to satisfy the growing demand of the Philippine market. A year later, Shell likewise entered the Philippine distribution market.

The first petroleum refinery in the Philippines went on stream on July 30, 1954. It was founded by Caltex Inc. at a cost of P60 million in Bauan, Batangas, and had an initial capacity of 13,000 bbl/d. Presently, the Caltex refinery has a total capacity of 70,800 bbl/d. The establishment of this first petroleum refinery was largely due to the efforts of the Philippine government, which offered fiscal incentives to any company willing to establish a petroleum refinery in the country. These incentives, such as a five-year exemption grant from customs duties on all purchases of equipment, machineries and supplies, were provided under Republic Act No. 387, or more commonly known as the "Petroleum Act of 1949".

July 1961 marked the establishment of the country's second petroleum refinery. The Bataan Refining Corporation (BRC) was built at a cost of P120 million in Limay, Bataan and had an initial capacity of 25,000 bbl/d and has a current capacity of 217,000 bbl/d. The refinery was jointly owned by Esso (57%) and Mobil Oil Co. (43%). By the end of 1961, the Philippine petroleum industry had a total refinery capacity of 60,600 bbl/d.

The number of petroleum refineries in the Philippines doubled in 1962. The first to be built that year was the Pilipinas Shell Refining Company Inc. in Tabangao, Batangas. The refinery was constructed at a cost of P65 million and had an initial capacity of 25,000 bbl/d. This was jointly owned by Shell Petroleum Co. Ltd. of London (75%) and Insular Life/FGU (25%). As of 1992, this Shell refinery had a total refinery capacity of 72,800 barrels per day.

A month later, the Filoil Refinery Corporation was established in Rosario, Cavite. It was built at a cost of P60 million and had an initial capacity of 10,000 bbl/d. Demonstrating the particular attractiveness of the petroleum refining market in the 1960's, Filoil was jointly

[1]Department of Trade. Philippine Petroleum Industry. 1973. pp. 1-5.

owned by a group of 2,000 Filipino investors (67%) and by Gulf Oil Corporation (33%). In 1971, the petroleum industry was regulated, prompting the Filipino investors to sell their shares to Gulf Oil Corporation. By the end of that year, the Philippine refining industry's total refinery capacity stood at 217,200 bbl/d.

The period 1960-1972 was one of considerable expansion of the petroleum industry for it witnessed the establishment of three refineries, bringing the total to four. Moreover, during this period, total refinery capacity grew from 35,800 bbl/d in 1960 to 289,100 bbl/d at the end of 1972. This represents an average annual increase of 14.94%. It is important to note that these four petroleum refineries were situated in provinces where crude oil can be speedily, economically and conveniently delivered by the supplier, having been constructed in provinces with excellent seaport facilities.

In addition to the four modern petroleum refineries, there were six petroleum marketing companies by the end of 1972. These were Caltex, Inc., Esso, Inc., Filoil Marketing Corporation, Getty Oil, Mobil Oil, Inc., and Shell, Inc. Mobil and Getty sourced their products from the BRC and Shell refineries, respectively.

By 1973, repercussions were felt in the Philippines refining industry as the world experienced the adverse effects of the first oil price shock. Recognizing the strategic importance of petroleum to the economy, the government created the Philippine National Oil Company (PNOC), by virtue of PD No. 334, on November 9, 1973. The PNOC was to take direct, intermediate and significant participation in the domestic petroleum industry.[2] Over a month after its establishment, the PNOC acquired Esso, which during that time owned 51% of BRC. Esso withdrew from the Philippine market due to financial reasons. Their financial situation worsened in 1972 when they reported a net loss of P9.59M, down from a P7.69M net loss in 1971. Several years later, Mobil was forced to sell out, providing means for PNOC's 100% ownership of the BRC. Four months after PNOC's acquisition of Esso, the controlling shares of Filoil Refining Corporation were transferred from the National Development Corporation (NDC) to the PNOC. Eventually, the Filoil Refinery was dismantled and its processing facilities transferred to the BRC.

For the next ten years (1974-1983), realignments continued in the petroleum industry. With the acquisitions of Mobil and Basic Landoil (Getty) by Caltex and Shell, respectively, the number of marketing companies and petroleum refineries in the country was reduced to three: Caltex, Petron and Shell. These realignments were largely due to financial factors. For instance, for the period 1972-1983, the entire petroleum industry posted an average net profit margin of only 0.20%, compared to the 3.75% for 1970-71 (Table B-1). The significant drop in rate of return can be attributed to the 31% increase in the landed cost of crude oil; during the period the F.O.B price of crude oil and the peso-dollar exchange rate registered annual average growths of 25.36% and 4.96%, respectively. It is important to note that the petroleum industry is a raw material-intensive industry, for crude accounts for over 80% of total product cost. Hence, increases in the crude oil price significantly affect the cost structure of the firm.

---

[2]Bernardo M. Villegas. Strategies for Crisis. (Center for Research and Communication: 1983). p. 65.

Table B-1
Profitability Ratios and the Average Crude Oil Price (US$ F.O.B. per barrel)

Year	Net Profit Margin (%)	Crude Oil Price (%/bbl)	Peso-Dollar Rate (P/US$)	Landed Crude Oil Cost (P/bbl)
1970	4.90	1.54	5.92	
1971	2.60	1.91	6.43	17.71
1972	-1.30	2.06	6.67	19.41
1973	0.80	2.48	6.76	26.38
1974	-0.70	9.31	6.73	81.28
1975	-0.30	10.68	7.25	99.20
1976	0.90	11.52	7.44	111.09
1977	0.60	12.39	7.40	116.33
1978	0.26	12.56	7.37	117.21
1979	-0.61	17.02	7.38	160.94
1980	0.01	28.82	7.51	278.82
1981	1.29	33.98	7.90	337.54
1982	1.08	32.81	8.54	355.60
1983	0.33	29.08	11.11	380.48

Source of Basic Data: SEC Top 1,000 Corporations Energy Regulatory Board
Note: Net profit margin figures for 1970-77 are based on R.S. Roques's M.S.I.E. Thesis (82)

B.3 Basic Conditions

B.3.1 Product

The pricing of petroleum products is economically very important due to its effect on the country's overall price index, strategic value to the industrial sector, and importance as an input for power generation and transportation. In addition to use in the industrial sector important petroleum products currently being produced include avturbo, premium and regular gasoline, diesel, fuel oil, kerosene, LPG, asphalts, solvents, and naphtha.

The importance of petroleum products to the economy, in general and to the industrial sector, in particular, can be seen from the 1979 and 1983 Input-Output (I-O) Tables. In the National Economic Development Authority's (NEDA) 1983 Update of the Inter-Industry Accounts, petroleum products registered the largest forward linkage effects, with an index of sensitivity of 2.017 (Table B-2). This represents an 8.97% increase from the 1979 figure. The index of sensitivity indicates the importance of a particular sector as a supplier of raw materials as well as services relative to other sectors.[3]

[3]National Economic and Development Authority. The Inter-Industry Accounts of the Philippine: 1983 Update. p. 24

Table B-2: Comparative Forward Linkage Effects, 1979 and 1983

SECTOR	Forward Linkage			
	1979		1983	
	U(i)	Rank	U(i)	Rank
Crops	1.196	6	1.096	7
Livestock and poultry	0.804	16	0.794	15
Fishery	0.611	22	0.684	18
Forestry and logging	0.926	10	0.890	13
Metallic mining	0.669	20	0.646	22
Non-metallic mining/quarrying	1.630	4	1.628	3
Food processing	1.176	7	1.276	6
Beverage and tobacco manufacture	0.693	17	0.690	17
Textile and leather products	0.845	13	0.810	14
Wood and wood products, paper, publishing and printing	1.072	8	0.904	12
Chemical and chemical products	1.689	2	1.594	4
Petroleum products	1.851	1	2.017	1
Non-metallic mineral products	0.677	19	0.644	20
Basic metals	1.621	5	1.306	5
Metal products and machinery	0.889	12	1.029	9
Miscellaneous manufactures and scrap	0.638	21	0.666	19
Construction	0.610	23	0.581	23
Electricity, gas and water	0.610	15	0.949	11
Transportation, communication and storage	0.901	11	1.081	8
Wholesale and retail trade	1.635	3	1.811	2
Finance, insurance and real estate	0.840	14	0.713	16
Government services	0.540	24	0.521	24
Private services	0.986	9	0.990	10

Source: NEDA Input - Output Table

Based on the 1983 matrix of technical coefficients, among the more petroleum-intensive sectors are electricity, gas and water; non-metallic mineral products; transport, communication and storage services; and non-metallic mining. Petroleum products comprised 47.5%, 22.5%, 16.7% and 9.3% of the total inputs of these industries, respectively. Based on the DOE's 1991 figures on petroleum product consumption by industry, the power generation, mining, and transportation (includes land, domestic marine and domestic aviation) sectors accounted for 42.9%, 4.0% and 9.9%, respectively.

B.3.2 Supply

B.3.2.1 Refinery Capacity

Presently, the Philippine petroleum industry's total refining capacity stands at 298,600 barrels per stream day. Of the industry's 298,600 bbl/d capacity, 155,000 bbl/d, or 51.9%, belongs to the BRC, while the refining capacities of Caltex and Shell are 70,800 bbl/d (23.7%) and 72,800 bbl/d (24.4%), respectively. One thing readily noticeable from these figures is the way BRC's capacity has exceeded that of Caltex's and Shell's. From an initial capacity of 24,800 bbl/d in 1961, it has increased to 155,000 bbl/d by 1992, representing a 6.1% annual average growth. The Caltex and Shell refineries posted annual average rates of 4.6% and 3.6%, respectively. However, the bulk of the BRC's capacity expansion took place in 1972, one year before the BRC was acquired by Petron. Both Shell and Caltex had similar plans of expanding refinery capacity to 130 x 10^6 bbl/d and 100 x 10^6 bbl/d, respectively,[4] however, neither plan was implemented.

Since the construction of the first petroleum refinery in 1954 until 1973, total refinery capacity grew at an annual average rate of 8.97%. However, after the first oil crisis in 1973, expansions of refinery capacities have been limited. From 1972-1992, total refinery capacity grew by only by 0.16% annually (Table B-3).

---

[4]Department of Trade. Philippine Petroleum Industry. 1973. p. 7.

Table A-3
Historical Refining Capacity (in thousand barrels per stream day)

Year	Refining Capacity	Utilization Rate (%)	Petroleum Consumption
1992*	298.6	78.57	na
1991	296.2	71.20	226.7
1990	288.6	77.23	234.2
1989	297.0	65.86	223.6
1988	290.5	64.32	199.1
1987	289.0	57.81	184.0
1986	289.0	50.88	158.2
1985	289.0	46.04	149.3
1984	287.0	53.49	168.3
1983	289.0	59.74	204.0
1982	293.0	59.39	203.8
1981	291.5	60.47	203.9
1980	291.5	64.84	216.8
1979	270.0	74.76	232.2
1978	270.0	72.88	225.4
1977	259.1	73.88	217.1
1976	259.1	70.01	200.6
1975	289.1	62.32	195.6
1974	289.1	55.12	181.4
1973	289.1	62.28	194.2
1972	289.1		
1971	217.1		
1970	209.7		

Source: Department of Energy
*October YTD level

This slow growth in total refinery capacity can be attributed to two factors. First, for the period 1973-1991, domestic petroleum consumption averaged only 0.9% of the annual growth. Moreover, beginning in 1980, petroleum consumption started declining and eventually bottomed out in 1985.

Second, capacity utilization rates have never exceeded 75% since 1972, even during the time when petroleum consumption approached the 85,000,000 bbl plateau. With such capacity utilization rates, the industry can absorb a 25% increase in crude charge, but the product slate produced will not match the consumption pattern.

B.3.2.2 Capacity Utilization

In the last five years, firms have been forced to increase their capacity utilization rates to satisfy increasing demand. In 1991, the industry posted a capacity utilization rate of 71.2% (Table B-4). This rate assumes that all three refineries were on stream 365 days during the year.

Table B-4: Refinery Capacity Utilization (in thousand barrels)

	BRC	CALTEX	SHELL	TOTAL
1992				
Refinery Capacity	155.0	70.8	72.8	298.6
Crude Run	110.6	61.9	62.1	234.6
Capacity Utilization	71.4%	87.4%	85.3%	78.6%
1991				
Refinery Capacity	155.0	68.4	72.8	296.2
Crude Run	102.2	50.1	58.6	210.9
Capacity Utilization	65.9%	73.2%	80.5%	71.2%
1990				
Refinery Capacity	155.0	61.6	72.0	288.6
Crude Run	116.2	52.0	54.7	222.9
Capacity Utilization	75.0%	84.4%	75.9%	77.2%
1989				
Refinery Capacity	155.0	68.0	74.0	297.0
Crude Run	85.6	53.1	56.9	195.6
Capacity Utilization	55.2%	78.1%	76.9%	65.9%
1988				
Refinery Capacity	155.0	68.0	67.5	290.5
Crude Run	91.2	48.5	49.3	189.0
Capacity Utilization	58.8%	71.3%	73.0%	65.1%
1987				
Refinery Capacity	155.0	68.0	66.0	289.0
Crude Run	86.3	49.7	40.9	176.9
Capacity Utilization	55.7%	73.1%	62.0%	61.2%

Source: Department of Energy

The utilization rate of the industry is expected to be increased even further in 1992. During the first nine months of the year, net domestic consumption amounted to 71,585,000 bbl. If this figure is annualized, domestic consumption this year could exceed 95,000,000 bbl. Hence, the capacity utilization rate might have to be increased to approximately 87%.

Therefore, at the rate petroleum consumption has been increasing for the past five years, the industry has shown justification for capacity expansions and/or de-bottlenecking operations.

B.3.3 Refinery Production

In order to satisfy the ever-growing petroleum needs of the economy, petroleum refinery production has been increasing for the past five years (Table B-5). During the 1987-1991 period, refinery production grew at an average rate of 7.6% per year.

Table B-5: Refinery Production (Excludes Refinery Contracts) (in thousand barrels)

Products	1992*	1991	1990	1989	1988	1985
Aviation Turbo	2,981	3,454	3,421	4,420	4,978	3,281
Premium Gasoline	7,412	8,914	10,863	9,150	8,610	7,763
Regular Gasoline	2,472	2,953	3,398	3,450	3,078	3,230
Kerosene	3,236	3,299	3,897	3,415	2,830	2,569
Diesel	20,017	24,159	23,729	20,806	20,840	16,794
Fuel Oil	20,092	24,132	26,428	22,160	20,728	20,410
LPG	2,164	2,776	2,703	2,276	2,390	2,309
Asphalts	215	333	300	365	285	280
Solvents	388	777	568	469	345	274
Naphtha	2,685	3,379	1,977	1,256	2,352	1,443
Total Marketable Products	61,662	74,176	77,284	67,767	66,436	58,353
In-Process & Intermediate			469	573	584	469
Add: Refinery Fuel & Loss			2,839	3,071	3,052	2,856
TOTAL OUTPUT	64,445	77,484	80,928	71,403	69,761	60,984

Source: Department of Energy
* September YTD levels

In addition, for the past five years, domestic refinery production has accounted for 85.4% of the country's total net domestic consumption, while imports, on the other hand, have contributed an average of 14.6% (Table B-6). However, it is important to point out the increase in petroleum product importations (primarily diesel fuel) for the past two years: from only 6,354,000 bbl in 1986, petroleum product importations have ballooned to 62,880,000 bbl in 1991. This increase in consumption can be attributed primarily to two

BEST AVAILABLE COPY

factors. The first factor is the government's reliance on diesel-powered gas turbines to ease the electrical energy shortage. The second factor is the large price differential between gasoline and diesel fuel. This has forced a large number of private car owners to shift to diesel-powered vehicles, thus distorting the consumption pattern.

Table B-6: Supply/Demand of Petroleum Products (in thousand barrels)

Year	Production	Exports	Available for Home Use	Consumption	% Self Sufficiency
1991	74,176	8,237	65,939	79,849	82.58%
1990	77,282	5,232	72,050	81,478	88.43%
1989	67,769	3,243	64,526	78,648	82.04%
1988	64,974	4,441	60,533	69,804	86.72%
1987	58,353	1,834	56,519	64,790	87.23%
1986	51,274	2,929	48,345	55,603	86.95%
1985	46,427	985	45,442	52,396	86.73%
1984	53,427	2,487	50,940	58,953	86.41%
1983	60,104	3,424	56,680	71,619	79.14%
1982	61,013	1,922	59,091	71,377	82.79%
1981	61,062	1,528	59,534	71,569	83.18%
1980	65,600	1,359	64,241	75,858	84.69%

Source: Department of Energy

B.3.3.1 Raw Materials

The most essential raw material in the refinery process is crude oil; it accounts for about 87% of the petroleum companies' total cost, excluding taxes and duties (See section 8 on cost structure). Procurement of the country's crude oil supply is a rather complicated process.

On the average, it takes about four months from the time the order for crude is placed with the supplier until the time when the refined petroleum products reach the consumers.[5] Thus, due to the length of time involved in the process flow from the oil source to the final consumer, there are times when the petroleum firms are able to sell their refined petroleum products from crude bought at a lower price at an earlier time. Under such situations, the petroleum company earns "windfall" profits or inventory gains. In such

[5]NOC. Primer on Oil Prices. 1987. p. 16.

cases, the

government applies a certain inventory gains or windfall tax. Presently, the Bureau of Internal Revenue (BIR) imposes a 65% surtax on windfall profits realized by the petroleum firms.

Conversely, a petroleum company could realize inventory losses when it sells the products at lower prices from crude oil purchased at an earlier higher price. At the present time, the petroleum firms are reimbursed for these losses through the OPSF.

Currently, local petroleum companies have two alternative ways of procuring their crude oil supply: i)through government-to-government supply or term contracts; or ii)spot purchases on the open markets.

Historically, government selling prices (GSP) are relatively higher than the spot prices, largely because of the premium paid to assure buyers of a steady supply of crude oil (Table B-7). These term contracts usually run for one year and can be renewed. The government-to-government contracts are extremely attractive in times of tight crude oil supply. The majority of these term contracts in the Philippines were initiated by Petron; lately, however, most of these contracts have expired.

Table B-7: Government Selling Price vs. Spot Prices
Second Quarter of 1988 (US$/bbl)

Crude Type	Spot Price	GSP
Arab Light	14.68	17.52
Iran Light	14.60	17.50
Kuwait	13.95	16.67
Attaka (Indonesia)	16.65	18.79

Source: Department of Energy

On the other hand, spot prices tend to be lower than government selling prices, largely because the former is short term, can vary daily and continued supply is not assured. In the spot market, the availability of crude oil supply is unpredictable. Recently, because of the glut in crude oil, petroleum companies have been securing the majority of their supply from the spot market. This situation may, however, quickly change depending on the developments in the very volatile Middle East region. Hence, petroleum companies usually diversify their sources of crude oil supply and methods

of procurement, both for security and cost benefit reasons.[6]
Since the early 1970's, the majority of the Philippine crude oil supply has originated from the Middle East region. The only time less than 50% of the country's supply was procured from the Middle East was in 1985, when supply from the region accounted for only 46.34% of the total. During this period, the shares of crude imports from Malaysia and China increased to 20.4% and 15.7% from 5.0% and 9.7%, respectively. This was largely due to the government's effort in establishing government-to-government contracts with oil-exporting countries in the Asian region. In the 1980's, the Middle East accounted for 65.4% of the total supply (Table B-8); a marked reduction from the 95% share in the early 1970's. This reduction is due largely to the efforts of the country to develop indigenous energy resources and to diversify sources of crude oil. The government's development efforts were rewarded in 1976 with the discovery of the first Philippine oil field. Since then, local crude oil production has accounted for close to 5% of the country's total crude oil supply.

During the first three quarters of 1992, close to 80% of the country's crude oil needs were sourced from the Middle East–with Saudi Arabia accounting for more than 60% of this total. Malaysia was the highest non-Middle East crude oil source at 7,412,000 bbl, or 10.9% of the total. During this period, local crude oil production contributed only 1.5% of the crude oil supply.

B.3.3.2 Public Policies

Petroleum is a highly politically and economically sensitive product largely due to i)the effects of its prices on the general price index and ii)its importance to the industrial sector. Due to this strategic value to the economy, the government has heavily regulated the petroleum industry.

Due to the numerous regulations affecting the petroleum industry, profits associated with refining and marketing of refined petroleum products have been reduced. One factor is the government's policy of limiting cost recovery increases to changes in crude oil importation costs. The basis of this policy is Letters of Instruction No. 1441, dated November 20, 1984, which states that OPSF adjustments shall be limited to import cost of crude oil and shall not include movements in the petroleum companies' operating and other costs. This may be a significant factor in the reduction of investments in the industry.

---

[6]Ibid., p. 10.

Table B-8: Crude Supply by Country of Origin
(Based on Loading Date)
(in thousand barrels)

	1992*	1991	1990	1989	1988	1985	1980
MIDDLE EAST							
Kuwait	2,841		6,748	10,024	9,966	8,068	9,385
Saudi Arabia	33,528	34,682	25,659	9,696	4,579	8,855	27,831
Iran	7,612	11,408	5,331	15,137	12,901	2,157	
Oman			1,030		5,440		926
Dubai		10,045	17,777	9,929	9,181	2,850	2,021
Iraq			3,843	4,224	1,314	889	7,843
United Arab Emirates	8,435		1,133	4,130	4,062		
Qatar	2,045	4,247	4,009	2,273	2,752		1,344
Neutral					1,785	1,051	
Abu Dhabi							602
Sub-Total	54,461	60,382	65,530	55,413	51,980	23,870	49,952
OTHER REGIONS							
Malaysia	7,412	7,130	7,474	7,859	9,244	10,498	3,561
China	760	2,989	1,154	3,875	4,208	8,088	6,965
Brunei	3,553	4,562	4,491	2,219	2,138	545	1,455
Indonesia	1,011	1,432	708			4,417	6,081
Australia			430	1,520	3,214	1,425	
Pakistan		161	311				
Mexico							
Sub-Total	12,736	16,274	14,568	15,473	18,804	24,973	18,062
Total Imports	67,197	76,656	80,098	70,886	70,784	48,843	68,014
Philippines	1,047	1,164	1,720	1,906	2,105	2,671	3,771
TOTAL	68,244	77,820	81,818	72,792	72,889	51,514	71,785

Source: Department of Energy
* First three quarters

B.3.4 Demand

B.3.4.1 Net Domestic Consumption

Three factors affecting demand for different petroleum products are product price, the price of the product's closest substitute and consumer income. Demand is directly proportional to both income and the product substitute's price. This means that an increase in the price of the substitute or income

amount would lead to an increase in product demand. On the other hand, demand is inversely proportional to product price, meaning that an increase in price would bring about a decrease in product demand.

During the first nine months of 1992, net domestic consumption amounted to 71,585,000 bbl. This represents an 18% growth over the previous year's figure. This increase in petroleum consumption occurred despite the slowdown in economic activity during the first three quarters of the year, when the gross domestic product (GDP) contracted by 0.41%.

On a per product basis (Table B-9), diesel fuel consumption posted the highest growth rate at 27%. The second highest growth rate was for lubes and petrolatum at 16.7%. Two other products that registered significant increases in consumption were LPG and fuel oil, with growth rates of 14.9% and 14.2%, respectively.

With such a large increase in consumption, diesel fuel replaced fuel oil as the most heavily demanded petroleum product in the country, accounting for about 35% of total domestic consumption. A close second is fuel oil, with a consumption share of 33.4%. These two products were followed by premium gasoline, LPG and kerosene with shares of 9.4%, 5.6% and 4.0%, respectively. Increases can likewise be discerned from petroleum product import and export data. During the past five years (1988-1991), petroleum product imports totalled 51,072,000 bbl, or an annual average growth rate of 12% (Table B-10). Diesel, fuel oil, and LPG comprised approximately 87% of the country's total petroleum product imports.

Petroleum product exports posted a growth rate of 35.0% for the same period (Table B-11). Exports consisted primarily of gasoline and naphtha. These two products accounted for over 82% of total petroleum product exports.

These trends represent the potential problem of demand for diesel outstripping refinery production. Unless either the price differential between gasoline and diesel is decreased, or refinery capacity is increased, this problem could continue to affect the local economy. Likewise contributing to the ballooning of diesel consumption is the installation of diesel-fired combustion turbines as stop-gap measures to address the current electric energy shortage.

Table B-9: Domestic Net Consumption (in Thousand Barrels)

Products	1992*	1991	1990	1989	1988	1980
Aviation Gasoline	23	28	36	39	39	62
Aviation Turbo	3,182	3,863	3,983	4,283	3,758	2,605
Premium Gasoline	6,703	8,112	9,390	8,830	7,751	5,866
Regular Gasoline	2,389	2,965	3,465	3,471	3,248	5,299
Kerosene	2,885	3,577	3,704	3,453	2,815	3,179
Diesel	24,930	26,888	25,053	22,335	19,186	17,428
Fuel Oil	23,911	28,245	29,694	30,348	28,002	37,129
LPG	3,976	4,742	4,516	4,183	3,503	2,411
Process Gas						233
Asphalts	245	327	286	341	317	343
Solvents	116	181	266	298	288	311
Lubes & Greases	769	910	1,70	1,058	887	988
Waxes & Petrolatum					3	1
Propylene						3
Others	9	11	15	9	7	
Total Products	69,138	79,849	81,478	78,648	69,804	75,858
Add: Refinery Fuel & Loss	2,447	2,907	3,070	3,051	2,771	3,283
TOTAL	71,585	82,756	84,548	81,699	72,575	79,141

Source: Department of Energy
*first three quarters

Table B-10: Petroleum Product Imports in Thousand Barrels

PRODUCTS	1991	1990	1989	1988	1987	1986	1980
Avgas	25	38	40	32	71	36	75
Avturbo	220	299			117		
Premium Gasoline	41	51					335
Diesel	1,220	2,377	4,815	1,044	967	599	1,120
Industrial Fuel Oil	7,946	4,927	4,663	4,181	5,510	4,182	10,486
Kerosene	218		598				131
LPG	1,146	1,904	2,028	1,193	708	584	774
Solvents		17		17			
Naphtha							64
Lubes/Additives/Basestock	175	98	94	73	136	64	
Heavy Vacuum Gas Oil				188	1,750	924	133
Slop Fuel Oil	147	139	132	155	133	29	
Special Fuel Oil							
Feedstock	174		875	371			
Used Lubricating Oil	10			9			
TOTAL	11,322	9,850	13,245	7,263	9,392	6,418	13,118

Source: Department of Energy

B.4 Marketing and Distribution System

The marketing and distribution of refined petroleum products is a relatively simple process. Initially, the distribution process began with the refinery selling its products to a designated marketing firm. This, however, is no longer the case, for the three local refineries have their own marketing arms. These marketing arms sell their products directly to consumers, government, and retail outlets. The US military bases (prior to 1992), industries, international consumers, and transportation companies comprise the direct consumers of petroleum. Petroleum companies usually offer these direct consumers a wide array of price discounts and rebates, depending on the sales volume, product, location and potential market. However, sales to retail outlets are usually on a cash basis, while industrial customers are normally extended credit terms.

Table B-11: Petroleum Product Exports (in Thousand Barrels)

	1991	1990	1989	1988	1987	1986	1983	1980
ENERGY PRODUCTS	8,229	5,232	3,240	4,434	1,741	2,908	3,359	1,347
Avgas								
Avturbo		233	499	242	4	187	359	
Gasoline/Naphtha	7,558	3,974	2,227	3,521	1,648	2,193	2,426	1,011
Diesel			463		72			8
Fuel Oil	671	1,025	50	669	16	500	171	243
Kerosene							359	
LPG			1	2	1	28	44	85
NON-ENERGY PRODUCTS	8	0	3	7	93	21	65	12
Asphalts					0		0	
Refinery Process Gas								
Solvents	8				86	17	27	
Lubes								
Greases			3	7	7	4	25	12
Waxes & Petrolatum								
Basestocks							13	
TOTAL	8,237	5,232	3,243	4,441	1,834	2,929	3,424	1,359

Source: Department of Energy
Note: 0 = less than 500 barrels

Retail outlets for petroleum products are generally classified into three types. These are i)service stations, ii)filling stations, and iii)curb pumps.[7] Service stations refer to petroleum product outlets with a building and a driveway located on the premises near or abutting a street or highway, where gasoline, kerosene, diesel, lubricants and any other derivatives including car care products may be dispensed and sold, and car care services rendered to motorists and the general public.

Filling stations refer to petroleum retail outlets with a building, driveway and pump island. Its business is generally confined to the sale of gasoline, kerosene, diesel, lubricants and any of their derivatives. Also included are marine outlets, whether mobile or stationary.

Curb pumps refer to petroleum retail outlets which generally have no separate building and driveway and offer no other services except to sell gasoline, kerosene, diesel, lubricants and any of their derivatives. Filling of the customer's vehicle or a purchaser's receptacle is done at the curb side of a road.

[7]Presidential Decree No. 1673, dated January 28, 1980.

As of November 1991, Caltex had the largest number of retail outlets nationwide at 1,164, followed by Petron and Shell, with outlets totalling 1,076 and 1,040, respectively (Table B-12).

Table B-12: Retail Outlets per Company

a)as of January 1989:

Area	Petron	Caltex	Shell	Total
Luzon	932	792	675	2,399
Visayas	185	157	254	596
Mindanao	139	240	192	571
TOTAL	1,256	1,189	1,121	3,566

b)as of November 1991:

Area	Petron	Caltex	Shell	Total
Luzon	700	673	657	2,030
Visayas	210	252	249	711
Mindanao	166	239	134	539
TOTAL	1,076	1,164	1,040	3,280

Source: Energy Regulatory Board

B.4.1 Market Structure

B.4.1.1 Number of sellers

Presently, there are three firms in the petroleum industry, down from six in the early 1970's: i)Caltex Inc. ii) Pilipinas Shell Petroleum Corporation and iii)Petron Philippines Corporation.

Caltex Inc. was founded on March 18, 1921 and is currently jointly owned by Chevron and Texaco, with each owning 50%. For the year 1991, Caltex's gross revenues amounted to P27,109 million, representing a 3.2% increase from the 1990 total. Net income amounted to P1,079 million, an increase of about 90% over the previous year's figure.

Pilipinas Shell Petroleum Corporation started its operations in the Philippines in 1914. During that time, it was known as Asiatic Petroleum Corporation (ASP) and managed the local marketing operations of the London-based Shell Transport and Trading Co. Ltd.[6] Currently, Shell's major stockholders are Shell Petroleum Company., Ltd. and Insular Life Assurance Co., Ltd., with percentage of interest amounting to 66.7% and 16.7%, respectively, with the balance split among several other companies. In 1991, Shell's gross revenues amounted to P32,490 million, representing a 42.9% increase from its 1990 figure. In addition, net income dropped from P886.4 million in 1990 to P770.8 million in 1991, representing a 13% decrease in earnings.

Petron Philippines Corporation came into existence when the PNOC acquired Esso Philippines, Inc. in December 21, 1973. With the Esso acquisition, PNOC became the largest petroleum firm in the country. Since 1977, Petron has led the industry in terms of total sales volume. This trend continued in 1991 when it registered gross revenues and net income of P43,496 million and P1,153.5 million, respectively. The former represents a 39.7% increase while the latter exhibits a 32.8% increase from their 1990 figures.

B.4.1.2 Number of buyers

Buyers in the petroleum industry are generally classified into five trade types. These are i)industrial consumers, ii)resellers, iii)international consumers, iv)Philippine government and v)(formerly) the US military bases.

The industrial consumers have always accounted for the largest share of the petroleum industry sales. For the period 1975-1991, their percentage share of total sales averaged 60.3%. Approximately 91.4% of these sales were in the form of diesel and fuel oil, largely because these two products are major inputs of marine engines, power plants and industrial furnaces. Hence, it is not surprising that among the most petroleum-intensive industries are power generation, mining, land transport and domestic

[6] "Pilipinas Shell now ahead of Caltex." Manila Bulletin. June 2, 1989. p. 25.

marine. During the first eight months of 1992, these four accounted for 47.4%, 3.3%, 3.4%, and 3.8%, respectively (Table B-13).

Table B-13: Petroleum Product Consumption by Industry (Percentage share)

INDUSTRY	1992*	1991	1990	1989	1988	1987	1980
Cement	1.95%	1.04%	2.03%	3.25%	1.21%	1.02%	6.27%
Sugar	1.77%	1.63%	1.85%	2.06%	2.01%	2.09%	2.18%
Coco & Vegetable Oil	0.64%	0.56%	0.69%	0.59%	0.62%	0.66%	1.91%
Mining	3.29%	4.02%	4.83%	5.21%	5.59%	5.89%	7.91%
Power Generation	47.42%	42.90%	38.80%	36.25%	36.39%	40.14%	31.83%
Fertilizer	0.26%	0.25%	0.21%	0.19%	0.15%	0.13%	0.92%
Logging/Wood Products	0.65%	0.86%	0.94%	1.15%	1.37%	1.58%	2.61%
Paper Processing	2.11%	2.03%	1.94%	2.13%	2.23%	2.46%	2.98%
Lube Refining	3.10%	1.21%	1.27%	1.12%	1.29%	1.29%	1.48%
Textile Mills	1.88%	1.89%	1.62%	1.83%	2.05%	2.02%	1.75%
Land Transport	3.39%	4.04%	3.94%	4.06%	4.15%	4.80%	2.89%
Domestic Marine	3.78%	4.34%	3.94%	3.75%	3.30%	3.54%	3.87%
Domestic Aviation	1.43%	1.57%	1.74%	2.01%	2.17%	2.50%	1.69%
Fishing Trade	3.15%	3.36%	3.05%	3.10%	3.02%	3.05%	1.33%
Glass Manufacturing	0.93%	1.03%	1.05%	1.17%	1.37%	1.45%	1.31%
Steel/Metal/Nickel Proc.	1.92%	2.02%	1.98%	1.92%	1.75%	1.66%	9.98%
Contractors	1.29%	1.48%	1.10%	1.37%	1.05%	1.06%	2.68%
Ceramics	0.32%	0.35%	0.30%	0.34%	0.37%	0.44%	0.38%
Rubber & Tires	0.31%	0.32%	0.34%	0.39%	0.32%	0.41%	0.33%
Chemicals	1.40%	1.42%	1.40%	1.41%	1.99%	1.54%	1.07%
Tobacco	0.25%	0.21%	0.23%	0.21%	0.21%	0.27%	0.17%
Food Processing	3.37%	3.64%	3.32%	3.24%	3.15%	3.20%	1.17%
All Others	13.27%	13.61%	17.52%	16.99%	18.11%	12.57%	7.24%
Refinery Fuel & Loss	2.09%	6.21%	5.91%	6.28%	6.15%	6.23%	6.12%
Total Industry	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Source: Department of Energy
*first eight months

"Resellers" are basically the retail outlets for such products as gasoline, kerosene, and diesel oil. During the eight-month period, resellers accounted for 34.8% of the industry's total domestic and international sales. Since 1975, resellers account for the second largest percentage share of the industry's total sales volume (Tables 3-14 and 3-15).

Table B-14: Petroleum Sales by Trade Type

Trade Type	1992*	1988	1987	1986	1980	1975
Industrial Sales	39,740,996	43,334,510	40,728,457	33,326,107	53,022,849	42,602,441
Resellers	22,922,609	23,097,756	21,670,529	19,056,981	22,443,288	22,961,692
Phil Government	686,930	1,032,990	1,023,514	902,060	1,417,025	1,690,018
U.S. Bases	19,240	366,192	370,484	336,813	15,059	367,455
Int'l Sales	2,512,189	2,758,421	3,067,459	2,231,264	2,651,830	1,668,962
Total	65,881,964	70,589,869	66,860,443	55,853,225	79,550,051	69,290,568

Table B-15: Petroleum Sales by Trade Type (Percentage share)

Trade Type	1992*	1988	1987	1986	1980	1975
Industrial Sales	60.32%	61.39%	60.92%	59.67%	66.65%	61.48%
Resellers	34.79%	32.72%	32.41%	34.12%	28.21%	33.14%
Phil Government	1.04%	1.46%	1.53%	1.62%	1.78%	2.44%
U.S. Bases	0.03%	0.52%	0.55%	0.60%	0.02%	0.53%
Int'l Sales	3.81%	3.91%	4.59%	3.99%	3.33%	2.41%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Source: Department of Energy
*first eight months

Philippine government, US bases, and International sales account for only 4.9% of the total sales of the industry. Sales to the Philippine government refer to purchases by government agencies such as the GSIS, PNB, DBP and others. Not included in this trade type are purchases made by such government owned and/or controlled organizations as the National Power Corporation (NPC) and the Philippine Airlines (PAL). These are classified as industrial consumers and are further categorized as power generation and domestic aviation, respectively. During the first three quarters of 1992, the Philippine government share of total sales stood at 1.0%.

The International customers are now the third largest consumer group in the Philippines; a typical example includes the sales to international airlines. With the withdrawal of the US forces in the Philippines, this trade has surpassed sales to the US military bases. During the first eight months of 1992, international consumers accounted for 3.8% of total petroleum sales. The US military base sales dropped from a range of 0.5 to 0.6%, to just 0.03% of total petroleum sales in the country.

B.4.1.3 Barriers to entry

Essentially, there are four barriers to entry in the Philippines petroleum industry. These four are i)economies of scale, ii)high capital requirements, iii)access to distribution channels and iv)government regulations.

The first barrier to entry in the petroleum industry is economies of scale. Due to the government's pricing regulations, there is inadequate price and product differentiation in the industry. To recover operating expenses, firms have to increase their sales volume or improve production efficiency. By expanding sales volume, costs are spread over a larger base, lowering the average unit cost. For a new firm to enter the industry, it must be able to process crude oil at an average unit cost approximating that of the industry's. In order to achieve this, minimum sales volumes must be met. If the required sales volume is not met, the company is at a distinct cost disadvantage relative to existing firms.
The second barrier to entry is high capital requirements. Current construction cost of a refinery with an initial capacity of 100,000 bbl/d is approximately $750 million. Moreover, it would take approximately five years to complete construction.

In addition, firms in the industry have to maintain certain inventory levels of crude oil and refined petroleum to provide a buffer against any possible increases in price of crude oil and demand for refined petroleum. Petron's average inventory levels for crude oil and refined petroleum stand at about 70 and 35 days, respectively. The former is worth about P3.0 billion, while the latter amounts to close to P2.5 billion. Moreover, in times of tight crude oil supply, crude oil and product inventory levels could go up to as high as 120 days.

The third entry barrier is access to distribution channels. For a firm to be competitive in the industry, it should possess the necessary outlets to distribute the petroleum products nationwide. Distribution channels refer to depots, terminals and bulk plants where petroleum products are stored. In addition to these, retail outlets are also necessary for the sales of gasoline, kerosene, LPG and diesel fuel.

The fourth, and possibly the most significant, entry barrier to the petroleum industry is government regulation. The petroleum industry is a heavily regulated industry. Almost every aspect of the industry is regulated, from the importation of crude oil up to the distribution and eventual sales of the refined petroleum product.

The government pricing regulations are considered to be such a significant barrier to entry due to ERB's policy of limiting cost recovery to increases in the landed cost of crude oil. The basis of the policy is Letters of Instruction No. 1441, dated November 20, 1984, which states that adjustments in the OPSF shall cover only increases in crude oil and shall not include any adjustment for operating and other oil company costs. However, Section 5 provided that the Board of Energy (now the ERB) shall not be precluded in adjusting/restructuring the domestic petroleum product prices at any time when necessary in accordance with existing procedures.

B.4.1.4 **Vertical integration**

The Philippine petroleum industry is basically integrated, meaning that each of the three firms have integrated their production, transportation, refining and marketing activities. Fifteen years ago there were firms, such as Getty and Arabay, which were purely marketing companies.

B.4.1.5 **Horizontal Integration**

Among the three firms in the Philippine petroleum industry, Petron is the most diversified. Purely a petroleum firm in the 1973, it has been transformed into a total energy company in the 1980's. Among Petron's sister companies are PNOC Coal Corporation, PNOC Crude Oil Tankers and PNOC Marine Corporation. The PNOC Coal Corporation is engaged in coal mining and exploration, while PNOC Crude Oil Tankers is involved in overseas shipping, tankage, lighterage, and general transport of goods and products. Lastly, PNOC Marine Corporation is involved in shipbuilding and repair.

In terms of diversification in the industry, a close second to Petron is Shell. Shell's largest sister company is Philippine Petroleum Corporation, which is the country's sole manufacturer of lubricating oil basestock. Other subsidiaries of Pilipinas Shell are Shell Gas and Shell Chemicals Corporation. The former is a manufacturer and blender of LPG, gaseous hydrocarbon, oil and petroleum. The latter is a manufacturer, wholesaler and importer of chemical products, animal health products, pesticides and fertilizers.

B.4.1.6 **Product differentiation**

Essentially, there is no product differentiation in the petroleum industry, except possibly for premium gasoline. This is largely due to the fact that petroleum products are homogenous. Hence, the performance of the product (e.g. diesel or fuel oil) is basically the same regardless of brand, since manufacturing specifications are similar.

However, in 1982 there were efforts to differentiate premium gasoline. The "gasoline war" started in 1982 with Petron's introduction of REV 2000. Caltex responded immediately with the introduction of CX-3, claiming that CX-3 can remove and dissolve sticky engine deposits to bring out its optimum power.[9] Four years later, Shell introduced the Spark Alder, which it claimed provides the car owner a tune-up every time he fills up. However, several years after its introduction, Shell was forced to withdraw and reformulate the Spark Alder because of negative side effects on the car's engine. Several months later, Pilipinas Shell introduced Formula Shell to the market.

Efforts of the petroleum companies to differentiate gasolines were accompanied by intensive advertising and promotional campaigns, but were limited solely to premium gasoline.

---

[9]Mahal Kong Pilipinas, "The Petroleum Industry", The Philippines Best Top 1000 Corporations. 1988. p. 498.

B.4.1.7 **Market Shares**

For the year 1991, the market shares of Petron, Caltex, and Shell were 42.3%, 26.1% and 31.6%, respectively. These figures include sales to the NPC and the Philippine Petroleum Corporation (PPC). Market shares of the three firms for the last five years have been relatively stable, with no firm exceeding 43% (Table B-16). In addition, Petron continues to be the market leader in the industry, followed by Shell and Caltex.

Table B-16: Market Shares in the Petroleum Industry

YEAR	PETRON	MOBIL	SHELL	CALTEX	GETTY	OTHERS
1991	42.3%		31.6%	26.1%		
1990	42.15		30.6%	27.4%		
1989	39.1%		31.4%	29.5%		
1988	37.6%		30.1%	32.3%		
1987	38.7%		28.8%	32.4%		
1986	34.1%		30.5%	33.6%		1.8%
1985	37.7%		28.2%	33.6%		0.5%
1984	39.9%		25.6%	34.0%		0.5%
1983	44.3%	7.4%	21.3%	25.3%		1.7%
1982	40.5%	12.9%	20.5%	24.4%		1.7%
1981	38.2%	13.1%	19.9%	24.1%		4.6%
1980	38.6%	14.5%	16.1%	24.7%	1.6%	4.6%
1979	37.6%	13.4%	17.5%	24.1%	2.8%	4.6%
1978	29.2%	13.7%	19.0%	25.6%	3.4%	9.2%
1977	29.2%	14.2%	17.1%	26.6%	3.5%	9.4%
1976	27.3%	14.0%	18.6%	27.9%	3.8%	8.4%
1975	28.1%	13.5%	17.8%	28.2%		12.4%
1974	24.5%	14.7%	18.5%	31.2%		11.2%
1973	28.3%	14.5%	19.2%	28.0%		10.0%

Source: Petron Philippines

Since 1984, changes in the market share of the three petroleum companies have been minimal. For the period 1984-1991, Petron's market share averaged 39.5%, with a standard deviation of 2.65. Shell had an average of 27.1% and a standard deviation of 4.33, while the average market share and the standard deviation of Caltex were 29.3% and 3.80, respectively.

The relatively stable market shares of the three can be partly explained by the niches of the petroleum market they cover. For instance, Petron continues to lead the industry in terms of black products (e.g. fuel oil,

solvents, asphalts). In 1991, Petron accounted for 51.4% of the fuel oil market, or a total sales volume of 51.4 million barrels. For the past three years, Petron's average share of the fuel oil market stood at 52.2% (Tables 3-17 to 3-19). Petron's continued dominance of the fuel oil market is largely due to its ability to service NPC's requirements. NPC alone represents close to 15% of the total petroleum market. In 1988, Petron supplied 70% of NPC's requirements, with Shell and Caltex accounting for 16% and 14%, respectively.

Petron has the highest fuel oil yield in the Philippine industry. Product yield is basically determined by two factors: i)refinery configuration, and ii)crude oil type. In 1991, Petron processed 37.4×10^6 bbl of crude oil or close to 44% of the entire industry's production. Shell and Caltex processed/produced 26.9×10^6 bbl (31.9%) and 19.7×10^6 bbl (23.3%) of crude/fuel oil, respectively. NPC accounted for 57% of Petron's total fuel oil sales in 1988.

Table B-17: 1989 Market Shares per Product per Company

Product	Petron % share	Shell % share	Caltex % share
Avgas	100.0%	0.0%	0.0%
Avturbo	44.3%	28.4%	27.3%
Premium Gasoline	32.4%	29.2%	38.3%
Regular Gasoline	28.7%	32.0%	39.3%
Kerosene	32.6%	29.7%	37.7%
Diesel Oil	33.5%	33.1%	33.5%
Fuel Oil	53.0%	29.7%	17.3%
Sub-total Fuels	42.2%	30.7%	27.1%
LPG	32.4%	34.9%	22.7%
Asphalts	95.9%	0.0%	4.1%
Hydro/Solvents	83.1%	16.9%	0.0%
Wax & Petrolatum	100.0%	0.0%	0.0%
Lubricating Oils	22.2%	40.4%	37.5%
Greases	17.9%	40.2%	41.9%
Others	0.0%	100.0%	0.0%
TOTAL	41.8%	30.8%	26.8%

Source: Petron Philippines
* Total may not equal to 100% due to rounding-off

Table B-18: 1990 Market Shares per Product per Company

Product	Petron % share	Shell % share	Caltex % share
Avgas	100.0%	0.0%	0.0%
Avturbo	56.9%	22.4%	20.6%
Premium Gasoline	31.8%	30.6%	37.7%
Regular Gasoline	31.2%	32.9%	36.0%
Kerosene	33.1%	29.8%	37.1%
Diesel Oil	38.0%	32.2%	29.8%
Fuel Oil	52.3%	32.1%	15.6%
Sub-total Fuels	43.5%	31.4%	25.2%
LPG	35.0%	34.9%	21.4%
Asphalts	99.9%	0.0%	0.1%
Hydro/Solvents	78.4%	21.6%	0.0%
Wax & Petrolatum	100.0%	0.0%	0.0%
Lubricating Oils	24.2%	40.8%	35.1%
Greases	18.3%	41.1%	40.6%
Others	0.0%	100.0%	0.0%
TOTAL	43.1%	31.5%	24.9%

Source: Petron Philippines
* Total may not equal to 100% due to rounding-off

Table B-19: 1991 Market Shares per Product per Company

Product	Petron % share	Shell % share	Caltex % share
Avgas	100.0%	0.0%	0.0%
Avturbo	56.5%	21.8%	21.7%
Premium Gasoline	31.2%	32.5%	36.3%
Regular Gasoline	32.1%	34.1%	33.8%
Kerosene	33.7%	30.5%	35.9%
Diesel Oil	43.2%	29.9%	26.9%
Fuel Oil	51.4%	34.0%	14.6%
Sub-total Fuels	44.9%	31.5%	23.5%
LPG	34.7%	37.3%	20.0%
Asphalts	99.9%	0.0%	0.1%
Hydro/Solvents	36.4%	49.6%	14.0
Wax & Petrolatum	100.0%	0.0%	0.0%
Lubricating Oils	22.8%	43.8%	33.4%
Greases	18.9%	42.8%	38.3%
Others	0.0%	100.0%	0.0%
TOTAL	44.3%	31.9%	23.3%

Source: Petron Philippines
* Total may not equal to 100% due to rounding-off

Caltex has been the market leader for the past three years in the sale of white products (eg. gasoline, LPG and process gas). Caltex has the highest white product yield among the three petroleum firms; in 1991, gasoline, LPG and process gas accounted for 24.8% of total refinery production. White products accounted for only 20.1% and 13.7% of Petron's and Shell's total petroleum productions, respectively. Caltex has the largest number of retail outlets nationwide; in 1991, its market shares in premium and regular gasolines stood at 36.3% and 33.8%, respectively. For the period 1989-1991, its market share for the same products averaged 37.4% and 36.4%, respectively. Caltex has the lowest market share in LPG sales at 23.5%, compared to Petron and Shell's market shares of 34.7% and 37.9%, respectively.

Caltex leads the industry in kerosene sales, with a market share of 35.9% for 1991. Petron is ahead in the aviation turbo and diesel fuel market, with shares of 56.5% and 43.2%, respectively. In 1991, close to 40% of Caltex's and Petron's refinery production was diesel oil compared to Shell's 33%. Kerosene, avturbo and solvents accounted for 9.3%, 7.5% and 10.9% of

Shell's, Caltex's and Petron's total production, respectively.

In sales of lubricating oils and greases, Pilipinas Shell continues to lead the industry. This is a highly attractive and unregulated product sector. In 1991, Shell's market share for greases and lubricating oils stood at 32.8% and 38.3%, respectively.

The primary determinant of market share for gasoline is the number of service stations the firm has. It is important to note that there is an extremely large number of gasoline buyers, as such gasoline sales per buyer are small. In this regard, a number of outlets servers a larger market area. For LPG, the primary determinant of market share is the availability of supply. A firm that intends to lead the LPG market must be able to source the necessary supply either by importing or producing it. For the past five years the country has been importing an average of over 1.5 million bbl of LPG annually (Table B-20).

Table B-20: LPG Imports (in thousand barrels)

Year	LPG Imports
1992*	1,083
1991	2,028
1990	1,904
1989	1,146
1988	1,193
1987	708
1986	584
1985	615
1984	608
1983	876

*as of 3rd quarter

Source: Department of Energy

For diesel fuel, the important market share determinants are the number of retail outlets and the number of industrial accounts served by the company. The latter is included as a determinant because diesel is used not only for cars but also for industrial engines. Compared to retail sales (reseller), industrial accounts are relatively few and involve large volumes. Firms that are able to solicit the greatest number of industrial accounts are expected

to lead the diesel oil market. For avturbo, the primary determinant is the extent to which the company serves the Philippine Airline (PAL), since it is the largest consumer of avturbo.

Regarding fuel oil, the number of industrial accounts served by the firm and the extent to which the company supplies NPC are the determinants of share in the market. For solvents, asphalts and thinners, the number of industrial accounts served by the firm is the main determinant of market share.

B.5 Product Strategy and Advertising

Various process units are utilized to improve the quality and performance of the firm's different products. Desulfurization units remove sulfur from the distillation product streams. Sulfur is removed from the streams because of corrosive and other negative effects on the catalyst in the reforming process. The reformer upgrades the octane ratings of gasoline products. These process units are expensive and require a large investment.

Modernization and efficiency improvement programs are required to remain competitive. For example, Petron is currently undertaking a $32.2 million modernization and efficiency program for the BRC. This program is expected to be finished by the end of this year.

Another area of competition is in the sourcing of crude oil. Firms that are able to procure the most economical crude oil have an advantage over the other firms. ERB uses the monthly Philippine average landed cost of crude in setting product prices. Currently, Petron has the lowest average crude oil import cost in the Philippine industry.

Another area of competition in the industry concerns distribution capability. This refers to the number of depots, bulk plants, terminals and service stations of the firm. This is extremely crucial since petroleum products are distributed nationwide. Another area of competition concerns the discounts, credit and equipment the firms provide to different consumers. For instance, Shell's fuel pumps and service stations are more sophisticated than those of the other two companies, a marketing strategy of Shell applied to the gasoline and diesel fuel market.

The bulk of advertising comes from Shell and Petron. The primary factor limiting Caltex's advertising its difficulty justifying petitions for increases in the DOCT with large advertising expenditures. Advertising and promotional campaigns of the three firms reached their peak in the early 1980's, when the three firms attempted to differentiate their premium gasolines. During that time, quick response by competing companies to promotional gimmicks was evident. For instance, Caltex immediately introduced CX-3 after Petron's REV 2000 came out on the market.

B.6 Interaction Among the Firms

There are essentially five forms of interaction among the three firms in the industry: i)rationalization of supply, ii)consumer exchange, iii)hospitality arrangement, iv)the processing arrangement between Caltex and Petron, and v)procurement of crude oil supply. The first form of interaction, rationalization of supply, means that some firms share their products with another firm when the product is in short supply.

The second form of interaction is consumer exchange. This is due to the fact that the

Philippine market is largely subdivided, meaning that there are certain areas served solely by a certain petroleum company. For example, Caltex has a buyer in Masbate, but is well aware that Petron has a depot in that region which could readily serve the buyer's demand. Hence, one option is for Caltex to give that customer to Petron in exchange for another customer at some future date.

The third form of interaction is referred to as the hospitality arrangement among the firms in the industry. Under this form of interaction, there is a rationalization of certain depots. Firms share depots, storage and distribution points in order to reduce storage and distribution costs. This cost reduction benefits both the consuming public and the petroleum industry.

The fourth form of interaction existing in the petroleum industry is the processing arrangement between Caltex and Petron. Under this arrangement, Caltex was allowed up to 8,500 barrels per day out of BRC's 155,000 barrels per day refining capacity for a processing fee of $1 per barrel. This processing arrangement lasted for eight years and ended in 1991.

The fifth form of interaction in the industry is in the procurement of the crude oil supply. Such form of interaction was very evident in the early 1980's, when the PNOC allocated to Petron and the two privately-owned companies its crude oil supply. For instance, 24% and 3% of Pilipinas Shell's total crude oil was sourced from PNOC in 1983 and 1984, respectively. Presently, the three petroleum companies are free to procure their crude oil from any supplier they wish. These firms are, however, required to report their crude oil importation transactions to the ERB to ensure that these are undertaken according to market competitive conditions.

B.7 Performance

B.7.1 Employment

Based on the National Statistics Office's (NSO) 1987 Annual Survey of Manufacturing Establishments, the total number of persons employed in the local petroleum companies stood at 2,451, amounting to over P43.5 billion in total salaries and wages. The NSO annual survey showed that for the period 1973-1987, the total number of persons working in petroleum refineries increased by 6.8% annually. Total salaries for the same period grew by 23% annually.

Of the 2,451 persons employed in the different petroleum refineries in 1987, 927 are managers and supervisors and 1,101 are production workers, while the remaining 423 are non-production employees engaged in sales, sales delivery, advertising, credit collection, clerical and routine office functions.

B.7.2 Financial Accounts

In 1991, the Philippine petroleum industry reported gross revenues amounting to P103,094 million, which represents a 38.7% increase from its 1990 figure. Of the three petroleum companies, Pilipinas Shell posted the highest growth rate at 42.9%. Closely behind are Petron and Caltex, with growth rates of 39.7% and 32.4%, respectively.

In terms of net income, the petroleum industry registered a 28.9% growth in 1991. On a per-firm basis, Caltex and Petron posted growth rates of 87.8% and 32.8%, respectively, while

Pilipinas Shell's net income amounted to P770 million, a contraction of 13.0%. For the same year, the industry's total net income stood at P3,003.2 million.

APPENDIX C:

EXECUTIVE SUMMARY

C EXECUTIVE SUMMARY

C.1 Purpose of the Report

The U.S. Agency for International Development (AID) Mission in Manila (USAID/Manila) and AID Office of Energy and Infrastructure have commissioned K&M Engineering and Consulting Corporation to carry out a study to establish the cost structure and transfer Pricing for the Philippine Petroleum Industry. The main objectives of this report are: to determine oil policy guidelines, evaluate the current cost and regulatory conditions, analyze the capabilities of the oil refinery industry, and identify the present alternative approaches to the current Philippine oil industry pricing mechanisms. Appendix G describes the tasks to be performed under this study.

The staffs of the Philippine Office of Energy Affairs (OEA), the Energy Regulatory Board (ERB), the three refineries and several teams of experts have worked in assembling and interpreting data pertaining to the overall Petroleum subsector and preliminary results have been presented to the Philippine interested parties, USAID/Manila and representatives of the World Bank.

The present report outlines: the current characteristics of the Philippine refineries, their expansion plans, the sources of crude, the sources and markets of refined products, the cost components, and compares them with some of the subsectors' regional parameters. Its scope is included in Tasks 3 and 4 of Appendix G. The findings outlined in this report will contribute to the completion of future work that will lay the groundwork to model the economic behavior of the Philippine petroleum refinery and distribution network.

C.2 National and Regional Trends Affecting the Philippine Refining Industry

The Philippines are increasingly becoming dependent upon Middle Eastern crude oils. The percentage of Middle Eastern crude in the mix has increased from 63% in 1988 to approximately 84% in 1991. Middle Eastern crude oils contain a high level of sulfur, and processing high percentages of Middle Eastern crudes is not compatible with the stated goal of producing low sulfur diesel and fuel oil products in the Philippines. If low product sulfur levels become a priority, it will be necessary to either purchase larger amounts of low sulfur Far Eastern crude (at higher cost) or make a large investment in gas oil and/or heavy fuel oil desulfurization facilities. Figures for 1992 show that the percentage of Middle Eastern crudes in the mix is still high at approximately 80%, but there appears to be an increase in crude purchased from Malaysia.

The current demand for certain products is out of balance with the capabilities of the Philippine refining industry. It is necessary to import at least 20,000 BPD each of diesel fuel and intermediate fuel oil, as well as 5,000 BPD of LPG. Conversely, on account of the relatively low demand for gasoline in the national product mix, the refining industry produces excess naphtha which is exported to Japan as cracking stock and excess reformate which is exported as aromatics feedstock and/or gasoline blending stock.

Currently Philippine crude production represents less than five percent of the crude consumed. One key question in regard to future crude supply for the Philippines is whether there will be significant increases in the production of oil offshore of the Philippines. A recent discovery in the West Linapacan area flowed oil (33 API Gravity) at 18,868 BPD from three wells and another discovery off NW Palawan islands known as Shell Malampaya 1

flowed oil at 12,623 BPD along with the presence of large amounts of natural gas. It is hoped that this reservoir may hold in excess of 300 million barrels of oil. If the anticipated 300+ million barrels can be proven, then oil production in the range of 20,000 to 50,000 BPD (as a comparison, imports of crude in the first seven months of 1992 were at the rate of 253,000 BPD) may be achievable by 1995. If the initial estimates prove to be accurate, then the competitive position of the refiners in the Philippines should be enhanced with regard to crude oil supply and transportation cost.

The situation of the three Philippine refineries, their expansion plans, and their position vis-á-vis the region are outlined below.

C.3 Review of Asia-Pacific Trends

The demand for oil in the Asia-Pacific region is rising faster than for any other region of the world. The current demand for petroleum products in this region is in the range of 14 million barrels per day (BPD). It is estimated that petroleum product demand will increase annually by 4% to 6% reaching roughly 16 million BPD by 1995. At the same time, given the current oil production profile in the region, it appears that dependence on sources of oil from outside the region will grow. It has been estimated that based on stagnating crude oil production and rising product demand, it is possible that crude oil imports into the region may possibly double to 10 million BPD by the year 2000, with consumption at a projected level of at least 18 million BPD.

Currently, the basic distillation capacity, but more importantly, the conversion capability of the Asia-Pacific refining industry is inadequate to meet the anticipated product quantity and quality demand for the region. Conversion capacity represents the capacity of the refinery processing units which are capable of "converting" crude oil fractions into lighter boiling ranges or another form such as petroleum coke. It is anticipated that up to 44% of new refining investments on a worldwide basis will be employed in this region. For China and the Far East areas, the basic refining capacity is sufficient, but the availability of secondary (conversion and treating) units is inadequate. Japan has a fairly "complex" (a measurement of the extent of conversion and upgrading capacity) refining industry, but as in much of Asia, middle distillate demand cannot be met internally. Basic refining capacity in South Asia (e.g. India) is insufficient. In Southeast Asia, including Singapore, distillation capacity is more than adequate, but conversion (i.e. secondary) unit capacity is substantially short in this region.

At the same time that conversion and treating capacity is inadequate in this part of the world, many of the nations in this regions are placing more stringent quality requirements on the fuels produced in order to promote a cleaner environment. To accomplish this, the complexity and flexibility of the Asia-Pacific refining industry will be increased significantly over the next several years. One example of the emerging trends is the movement toward unleaded gasoline. It appears that most of the countries of Asia have announced programs to reduce the levels of lead in gasoline to 0.15 grams per liter, with some promoting an eventual total phase-out.

In addition to lead reduction, several countries in Asia are following the worldwide trend toward reformulated gasoline. As an example, Thailand has stated that it is their intention to reduce the level of aromatics in gasoline from 50% to 35% over the next three years and to add oxygenates to the gasoline.

The trend in diesel fuel quality is toward lower sulfur. It is anticipated that many countries in the region will impose standards that lower the sulfur in diesel from an average 0.5% in 1990 to 0.3% in 1993 to as low as 0.05% in 1997. It has recently been estimated that between 2.0 and 2.5 million barrels of refining capacity for the Asia-Pacific region are currently in the construction, engineering, or planning phases.

C.4 Shell Tabangao Refinery

The Shell petroleum refinery is located in the Philippine province of Batangas, approximately 70 miles south of Manila on the island of Luzon. Shell completed construction at the initial site of this refinery in 1962 with an initial capacity of 26,300 barrels per day. Since that time, there have been a number of crude distillation capacity additions and changes, bringing the current capacity to 72,800 barrels per day (BPD).

The Tabangao refinery is a simple hydroskimming refinery which is configured with naphtha hydrotreating/catalytic reforming for gasoline production and distillate desulfurization capabilities. This refinery has no conversion capacity.

Shell has undertaken a massive project to essentially construct a new 110,000 BPD refinery on the site of the existing refinery. This project has been designated as the Shell Tabangao Asset Renewal (STAR) project, and is scheduled for completion in mid-1994. The first stage of this project is currently nearing the end of the construction phase and involves the addition and upgrade of crude oil and products transfer and storage facilities. This project is referred to as the FIESTA project. The existing refinery will not be dismantled, but instead will be mothballed. This will provide spare crude oil distillation and processing capacity if needed in the future.

Butane and/or propane will be transferred to Shell Gas Eastern which maintains a duty-free zone for the movement of LPG to markets in Hong Kong, Malaysia, Thailand, Saipan, and Japan. In addition, LPG can be delivered from the SGEI facility as a pressurized liquid in trucks to the Philippine markets.

A single atmospheric crude distillation tower will be constructed to process all of the 110,000 BPD of crude oil. The tower will be configured to take a naphtha cut overhead and various middle distillate draw streams which can be recombined prior to desulfurization or can be sent to intermediate storage. A portion of the atmospheric tower bottoms will be sent to a thermal cracking (visbreaking) unit for viscosity reduction and mild conversion.

Shell made the decision to abandon the old equipment for a variety of technical and economic reasons. First of all, the refinery has a heavy dependence on Far Eastern crudes which are more expensive and the available supply of these crude is in great demand. Second, Shell feels that the existing refinery is inefficient from the standpoint of energy consumption, environmental control and working capital requirement. Third, the existing demand for middle distillate fuels in the Philippines cannot be met by the domestic refining industry. Therefore, Shell sees a need to provide more middle distillate to the national marketplace and has configured the new processing scheme accordingly.

The future crude slate is expected to provide a reduced dependence on relatively scarce Far Eastern crudes. The future crude mix is expected to be composed of 92% Middle Eastern crude (provides good middle distillate yields but are high in sulfur) and 8% Far Eastern crude. The residual stream from Far Eastern crudes can be segregated for sale as a high

quality cracking stock.

C.5 CalTex Batangas

The CalTex petroleum refinery is located in the Philippine province of Batangas, approximately 60 miles south of Manila on the island of Luzon. CalTex completed construction at the initial site of this refinery in 1954 with an initial capacity of 14,700 barrels per day. Since that time, there have been a number of crude distillation capacity additions and changes, bringing the current capacity to 70,800 barrels per day (BPD).

The Batangas refinery is a low conversion refinery which includes naphtha hydrotreating, catalytic reforming, distillate desulfurization, and fluid catalytic cracking. Fluid catalytic cracking (FCC) is a conversion process which provides a high degree of plant flexibility.

The capacity of CalTex Crude Distillation Unit #2 will be expanded from 36,000 BPD to 50,000 BPD, and will be capable of handling all anticipated crude types. The total capacity of the refinery after the crude unit revamp will be 82,000 BPD. To handle the increased flow of naphtha from the expanded distillation capacity, the naphtha hydrotreater will be expanded from 12,000 to 16,000 BPD. The catalytic reforming unit will be expanded by a less than proportionate 2,000 BPD to 9,000 BPD. The naphtha handling facilities of this location will also be expanded to match the additional increment of hydrotreated naphtha for export. The refinery revamp will be completed in 1994.

C.6 Petron Bataan Refinery

The Petron petroleum refinery is located on the Bataan peninsula, approximately 60 miles south of Manila on the island of Luzon. Standard Vacuum Refining Company (eventually Mobil) completed construction at the initial site of this refinery in 1960 with an initial capacity of 25,000 barrels per day. In 1971, a major plant expansion resulted in an increase in capacity to 117,000 BPD. In 1973, the Philippine National Oil Company (PNOC) took over all Esso concerns in the Philippines, and in 1978 the capacity was increased to the current 155,000 BPD. The Petron plant is a low conversion refinery which includes naphtha hydrotreating, catalytic reforming, distillate desulfurization, and Thermofor Catalytic Cracking (TCC).

Petron indicated that they are planning a project for the construction of an 18,000 BPD Gas Oil Hydrofiner. It is anticipated that this unit will be operational during the second half of 1994. The new gas oil hydrofiner will provide the capability to achieve 90% desulfurization of gas oil streams and LCGO from TCC from less expensive crude oils. The unit will be designed to operate at pressures in the range of 700 to 750 psi to produce a diesel product with a sulfur level of 0.4 weight %. Excess hydrogen is available from the current reforming facilities to achieve the proposed level of desulfurization. A project is currently underway to facilitate the enhanced recovery of LPG. It is anticipated that the production of LPG from the Petron refinery will increase from 4500 BPD to 5500 BPD.

There is also a study underway to examine the need for additional refining facilities in the Philippines. Included as part of the study is a determination of the potential for expanding the current site versus constructing a 100,000 BPD grassroots refinery in Mindanao or Visayas. It is recognized that the current refining network is long on gasoline and short on middle distillate production. Processing options aimed at conversion to middle distillate are being given strong consideration. Options under consideration include visbreaking and hydrocracking which would require the addition of a hydrogen plant.

C.7 Analysis of the Philippine Refining Industry

The Philippine refining industry is currently of moderate complexity when compared with this sector in other Asia-Pacific nations. The refining industries of Australia and Japan have the highest complexity in the region. However, it is important to note that the complexity factors for a number of nations including Indonesia, Thailand, Korea, Singapore, and Thailand will increase significantly as many of the major conversion addition projects are completed over the next several years. Without the addition of significant residual conversion capacity, the Philippines will be at a relative disadvantage to many of it's neighbors with respect to crude purchasing flexibility.

Shell runs the highest proportion of Far Eastern crudes in the mix, and not surprisingly the Tabangao refinery has the highest landed crude cost of the three refineries. A partial explanation for the high percentage of Far Eastern crude run at Shell may be the need to provide 12,000 barrels of lube feedstock to the PPC Lube Plant. The lowest average crude cost is maintained by Petron, which corresponds to the significantly higher percentage of Middle Eastern crude in the refinery input. Petron produces a large amount of fuel oil for the National Power Company, but the higher sulfur content of the crude mix is not a problem under present environmental regulations.

The gross refining margin has been calculated as the difference between the average per barrel refinery proceeds of production and the average cost of a landed crude oil barrel. This figure ranges from $2.74 per barrel at Shell to $5.71 per barrel at CalTex. As expected, the gross operating margin increases as the complexity and flexibility of the refinery increases.

After taking all known costs into account and estimating those not accurately known, a projection of the per barrel operating cost was provided. The estimated operating cost ranged from $1.31 per barrel at Shell to $2.23 per barrel at CalTex. Typical per barrel operating costs for North America would be in the range of $2.70 to $2.90 per barrel. It should be noted that North American refineries are typically more complex, and therefore should have higher operating costs. Recent information indicates that the operating cost for Singapore refineries are in the range of $1.50 or so per barrel. Given all of this, the operating cost structure of the Philippine refining industry appears to be within expected ranges.

By subtracting estimated per barrel operating expense from the gross operating margin, refinery operating margins were projected. The weighted average cash margin for the Philippine refining industry as calculated here is $2.08 per barrel. Based on this analysis, the refinery operating margins for the three Philippine refineries appear to be favorable within the range expected for plants of this complexity.

C.8 Capability to Meet Future Product Quality and Demand Requirements

Over recent history, refinery capacity in the Philippines has greatly exceeded the demand for product, while production levels have typically been lower than product demand. In conclusion, the Philippine Refining Industry has sufficient distillation capacity to balance the physical amount of petroleum consumed in the form of product. However, on account of the lack of sufficient conversion capacity and local product demand patterns, the industry cannot produce the appropriate state of products.

Projecting out to 1995, gasoline blending material should still be in excess, while the gap between diesel production and diesel demand may close somewhat on account of the STAR expansion project. LPG and fuel oil will most likely be in short supply, while the supply of jet fuel and kerosene should be close to balancing the demand.

In regard to product quality, there should be no problem providing unleaded gasoline in sufficient quantities to satisfy the marketplace. Because of the excess of reformer capacity and naphtha feedstock in the Philippines, octane requirements can easily be met. However, it should be noted that the unleaded gasoline will primarily be blended using high octane reformate and cracked naphtha streams which contain high concentrations of aromatics. The unleaded gasolines produced in the Philippines could easily exceed aromatics levels of 50%. A clear environmental trend in other parts of the world which is beginning to receive consideration in Asia (e.g. Thailand) is the reduction of aromatics levels in gasoline to the range of 25% to 30%. It does not appear that the anticipated projected processing configuration of the Philippine refining industry for 1995 will have the flexibility to accomplish a meaningful reduction in gasoline aromatics content.

Information obtained from the Philippine Office of Energy Affairs (OEA) projects the required diesel sulfur level decreasing from 0.8% in January 1993 to 0.6% in January 1994 to 0.4% in January 1996 to 0.25% in January 1997. It is anticipated that Shell will be able to produce diesel fuel with sulfur in the range of 0.25% to 0.3% when the STAR project is completed. Currently, Petron blends surplus kerosene and jet fuel to diesel to produce a low sulfur (0.5%) grade diesel which has a color advantage and is sold primarily to Metro Manila Transport. The remaining diesel fuel has a sulfur level of 0.9% and is sold primarily to industrial users. After the addition of a new gas oil hydrofiner, Petron expects to produce diesel fuel with 0.4% sulfur. Additional modifications would be required to produce 0.25% sulfur diesel. CalTex indicates that after the reforming capacity is expanded, enough hydrogen will be available to produce diesel with a sulfur level of 0.6%. In order to produce diesel fuel with lower sulfur levels, it will be necessary to purchase more Far Eastern crudes or modify the refinery.

After the completion of the STAR project, Shell will be in a position to provide heavy fuel oil with sulfur levels in the 2.0 to 2.5 weight % range on account of the partial desulfurization achieved in the thermal processing unit. As indicated previously, neither Petron or CalTex will be in a position to produce heavy fuel oils with sulfur levels below the range of 3.0 to 3.5 weight % with the current crude slate. As the sulfur requirements for fuel oil are lowered, a correspondingly higher proportion of Far Eastern (i.e. low sulfur) crude will need to be added to the crude slate. Currently, light low sulfur Far Eastern crudes carry a price premium of $3 to $4 per barrel over Middle Eastern crude. In addition, trends toward increased oil demand in Asia along with the movement toward internal refining of domestic crudes and exporting of products from Malaysia and Indonesia may serve to make Far Eastern crudes harder to obtain and more expensive. Two wild cards in this situation are the potentially large discoveries of oil in the Spratly Islands area and offshore Philippines.

An open letter was published, in August of 1992, in one of the local newspapers, from the presidents of the Philippine refining companies regarding the potential for environmental regulation to necessitate 0.3% sulfur levels in fuel oil. The implementation of such regulations would require either a huge increase in the percentage of Far Eastern crude in the mix or a large investment in residual desulfurization facilities, costing an estimated 250 to 500 million U.S. dollars. The economic impact of running high percentages of light sweet Far Eastern crude oils, given the current premium pricing, would be huge.

In conclusion, the Philippine refining industry has sufficient distillation capacity to balance the physical amount of petroleum consumed in the form of product. However, on account of the lack of sufficient conversion capacity and the local product demand patterns, the industry is not in a position to produce the appropriate slate of products. This situation should improve with the numerous upgrading and expansion projects currently underway. However, it is anticipated that there will continue to be shortages of certain products in the future, specifically diesel fuel and LPG. Finally, based on current plans, the Philippine refining industry would be almost totally dependent on light sweet Far Eastern crude oils for the production of low sulfur heavy fuel oils. A review of trends in the Asia-Pacific region results in the conclusion that Far Eastern crudes may be both more difficult to obtain and more expensive in the future.

APPENDIX D:

SUPPLEMENTARY FIGURES AND TABLES

Table VIII-1
5-YEAR FINANCIAL DATA ON PHILIPPINES OIL COMPANIES

From Financial Statements, Millions Pesos

	1987	1988	1989	1990	1991	AVERAGE	MINIMUM	MAXIMUM
CALTEX								
SALES	15,780	16,852	14,445	20,171	26,803	18,810	14,445	26,803
INCOME	(116)	151	223	575	1,079	382	(116)	1,079
TOTAL ASSETS	9,501	11,241	11,882	12,611	9,421	10,897	9,421	12,611
EQUITY	1,140	1,292	1,515	2,090	3,024	1,812	1,140	3,024
EQUITY AS % OF ASSETS	12.0%	11.5%	13.0%	16.6%	32.1%	16.6%	11.5%	32.1%
PETRON								
SALES	17,470	18,694	19,103	30,995	43,498	25,952	17,470	43,498
INCOME	461	758	859	868	1,154	820	461	1,154
TOTAL ASSETS	10,224	11,194	19,348	26,123	21,935	17,765	10,224	26,123
EQUITY	2,172	3,142	3,284	4,152	5,103	3,571	2,172	5,103
EQUITY AS % OF ASSETS	21.2%	28.1%	17.0%	15.9%	23.3%	20.1%	15.9%	28.1%
SHELL								
SALES	13,697	14,720	15,369	22,531	32,470	19,757	13,697	32,470
INCOME	302	578	881	886	771	680	302	886
TOTAL ASSETS	11,366	11,826	15,756	18,627	15,675	14,690	11,366	18,627
EQUITY	3,296	4,379	5,008	4,664	6,100	4,689	3,296	6,100
EQUITY AS % OF ASSETS	29.0%	37.0%	31.8%	25.0%	38.4%	31.9%	25.0%	38.4%
TOTAL INDUSTRY								
SALES	46,947	50,266	48,917	73,697	102,769	64,519	46,947	102,769
INCOME	646	1,487	1,944	2,329	3,003	1,882	646	3,003
TOTAL ASSETS	31,091	34,261	46,786	57,361	47,230	43,342	31,091	57,361
EQUITY	6,608	8,813	9,807	10,905	14,226	10,072	6,608	14,226
EQUITY AS % OF ASSETS	21.3%	25.7%	21.0%	19.0%	30.1%	23.2%	19.0%	30.1%
CALTEX								
RETURN ON SALES	-0.7%	0.9%	1.5%	2.8%	4.0%	2.0%	-0.7%	4.0%
RETURN ON ASSETS	-1.2%	1.3%	1.9%	4.6%	11.5%	3.5%	-1.2%	11.5%
RETURN ON EQUITY	-10.2%	11.7%	14.7%	27.5%	35.7%	21.1%	-10.2%	35.7%
PETRON								
RETURN ON SALES	2.6%	4.1%	4.5%	2.8%	2.7%	3.2%	2.6%	4.5%
RETURN ON ASSETS	4.5%	6.8%	4.4%	3.3%	5.3%	4.6%	3.3%	6.8%
RETURN ON EQUITY	21.2%	24.1%	26.2%	20.9%	22.6%	23.0%	20.9%	26.2%
SHELL								
RETURN ON SALES	2.2%	3.9%	5.6%	3.9%	2.4%	3.4%	2.2%	5.6%
RETURN ON ASSETS	2.7%	4.9%	5.5%	4.8%	4.9%	4.6%	2.7%	5.5%
RETURN ON EQUITY	9.2%	13.2%	17.2%	19.0%	12.6%	14.5%	9.2%	19.0%
TOTAL INDUSTRY								
RETURN ON SALES	1.4%	3.0%	4.0%	3.2%	2.9%	2.9%	1.4%	4.0%
RETURN ON ASSETS	2.1%	4.3%	4.2%	4.1%	6.4%	4.3%	2.1%	6.4%
RETURN ON EQUITY	9.8%	16.9%	18.6%	21.4%	21.1%	18.7%	9.8%	21.4%

BEST AVAILABLE COPY

Table VIII-2

PRO FORMA OPERATING EARNINGS BEFORE INTEREST & TAXES BASED ON ACTUAL YIELDS, PRICES AND EXPENSES

	TOTAL INDUSTRY DATA			CALTEX			PETRON			SHELL		
	1990	1991	1990/91	1990	1991	1990/91	1990	1991	1990/91	1990	1991	1990/91
PESO/LTR												
PRODUCT REVENUE	3.6995	4.7120	4.1948	3.8726	4.9963	4.4284	43.3273	53.4162	96.7435	3.7118	4.8213	4.2840
CRUDE COST	3.7817	3.8837	3.8316	3.7550	4.0521	3.9019	45.0214	43.8932	88.7146	3.9003	4.1014	4.0044
GROSS MARGIN	-0.0822	0.8283	0.3632	0.1176	0.9443	0.5264	-1.6941	9.7230	8.0289	-0.1885	0.7199	0.2816
PROCESSING				0.0100	0.0193	0.0146	-0.0662	-0.2010	-0.2672			
REFINERY EXPENSES	0.1265	0.1619	0.1438	0.1620	0.2081	0.1848	0.9270	1.9091	2.8361	0.1884	0.1520	0.1686
MARKETING EXPENSES	0.1832	0.2232	0.2027	0.1705	0.2308	0.2003	1.5983	2.2241	3.8204	0.2977	0.3133	0.3056
FREIGHT UNDERRECOVERY	0.0214	0.0222	0.0218	0.0205	0.0176	0.0191	0.2289	0.2685	0.4974	0.0271	0.0308	0.0289
SUBTOTAL	0.3310	0.4073	0.3683	0.3530	0.4565	0.4042	2.7522	4.4018	7.1539	0.5111	0.4959	0.5032
EBIT	-0.4108	0.4283	-0.0012	-0.2254	0.5071	0.1369	-4.4462	5.3212	0.6750	-0.3536	0.1368	-0.1240
FOREX ADVANTAGE	0.1040	0.1088	0.1054	0.1033	0.1114	0.1073	0.1027	0.1004	0.1016	0.1073	0.1128	0.1101
NET EBIT	-0.3068	0.5331	0.1041	-0.1221	0.6185	0.2442	-4.3435	5.4216	0.9766	-0.2463	0.2496	0.0128
$/BBL CRD												
PRODUCT REVENUE	23.94	27.15	25.51	25.11	28.77	26.92	23.18	25.81	24.41	24.19	27.77	26.04
CRUDE COST	24.25	22.43	23.36	24.11	23.38	23.75	23.87	21.10	22.57	25.16	23.68	24.39
GROSS MARGIN	-0.31	4.72	2.15	1.00	5.39	3.17	-0.70	4.70	1.84	-0.97	4.10	1.65
PROCESSING				0.07	0.11	0.09	-0.04	0.07	-0.05			
REFINERY EXPENSES	0.83	0.93	0.88	1.08	1.20	1.13	0.50	0.81	0.65	1.22	0.88	1.04
MARKETING EXPENSES	1.20	1.29	1.24	1.12	1.33	1.22	0.87	0.94	0.90	1.95	1.81	1.88
FREIGHT UNDERRECOVERY	0.14	0.13	0.13	0.13	0.10	0.12	0.12	0.11	0.12	0.18	0.18	0.18
SUBTOTAL	2.17	2.35	2.26	2.32	2.64	2.47	1.50	1.87	1.67	3.36	2.88	3.10
EBIT	-2.47	2.40	-0.09	-1.25	2.86	0.78	-2.20	2.83	0.17	-4.33	1.23	1.45
FOREX ADVANTAGE	0.67	0.62	0.64	0.68	0.64	0.65	0.66	0.58	0.62	0.69	0.65	0.67
NET EBIT	-1.80	3.02	0.55	-0.59	3.50	1.44	-1.54	3.41	0.79	-3.64	1.89	0.78
MEMO												
TOTAL CRUDE PROCESSED	80,926	77,486	158,412	18,981	18,783	37,764	41,997	37,303	79,300	19,946	21,400	41,346
BY PETRON FOR CALTEX				2,523	2,259	4,782	2,523	2,259	4,782			
NET CRUDE OWN ACCT(DIVISOR)	80,926	77,486	158,412	21,504	21,042	42,546	39,473	35,044	74,517	19,946	21,400	41,346
REF EXPENSE @ OWN REFINERY				1.21	1.35	1.28	0.47	0.76	0.61	1.22	0.88	1.04

BEST AVAILABLE COPY

Table VIII-3

PRO FORMA OPERATING EARNINGS BEFORE INTEREST & TAXES BASED ON ACTUAL YIELDS, PRICES AND EXPENSES

	TOTAL INDUSTRY DATA			CALTEX			PETRON			SHELL		
	1990	1991	1990/91	1990	1991	1990/91	1990	1991	1990/91	1990	1991	1990/91
MILLION PESOS												
PRODUCT REVENUE	47,597	58,047	105,644	13,240	16,714	29,954	22,586	24,930	47,515	11,772	16,403	28,175
CRUDE COST	48,655	47,844	96,499	12,838	13,556	26,393	23,447	20,334	43,781	12,370	13,954	26,324
GROSS MARGIN	(1,058)	10,204	9,146	402	3,159	3,561	(862)	4,596	3,734	(598)	2,449	1,851
PROCESSING				34	65	99	(34)	(65)	(99)			
REFINERY EXPENSES	1,627	1,995	3,622	554	696	1,250	482	782	1,264	591	517	1,108
MARKETING EXPENSES	2,357	2,749	5,106	563	772	1,355	630	911	1,741	944	1,066	2,010
FREIGHT UNDERRECOVERY	275	273	548	70	59	129	119	110	229	86	104	190
SUBTOTAL	4,259	5,017	9,276	1,207	1,527	2,734	1,431	1,803	3,234	1,621	1,687	3,308
EBIT	(5,262)	5,251	(31)	(771)	1,606	926	(2,293)	2,793	500	(2,219)	762	(1,457)
FOREX ADVANTAGE	1,338	1,316	2,654	353	373	726	645	559	1,204	340	384	724
NET EBIT	(3,944)	6,567	2,623	(418)	2,069	1,652	(1,648)	3,352	1,704	(1,879)	1,146	(733)
MILLION $												
PRODUCT REVENUE	1,937	2,104	4,041	540	605	1,145	915	904	1,819	482	594	1,077
CRUDE COST	1,963	1,738	3,701	518	492	1,010	942	740	1,682	502	507	1,008
GROSS MARGIN	(25)	366	340	21	113	135	(26)	165	137	(19)	89	69
PROCESSING				1	2	4	(1)	(2)	(4)			
REFINERY EXPENSES	67	72	140	23	25	48	20	28	48	24	19	43
MARKETING EXPENSES	97	100	197	24	28	52	34	33	67	39	39	78
FREIGHT UNDERRECOVERY	11	10	21	3	2	5	5	4	9	4	4	7
SUBTOTAL	176	182	358	50	55	105	59	65	125	67	61	128
EBIT	(200)	186	(14)	(27)	60	33	(87)	99	13	(86)	26	(60)
FOREX ADVANTAGE	54	48	102	14	14	28	26	20	46	14	14	28
NET EBIT	(146)	234	88	-13	74	61	-61	120	59	-73	40	32

BEST AVAILABLE COPY

Figure VIII-1

RETURN ON SALES

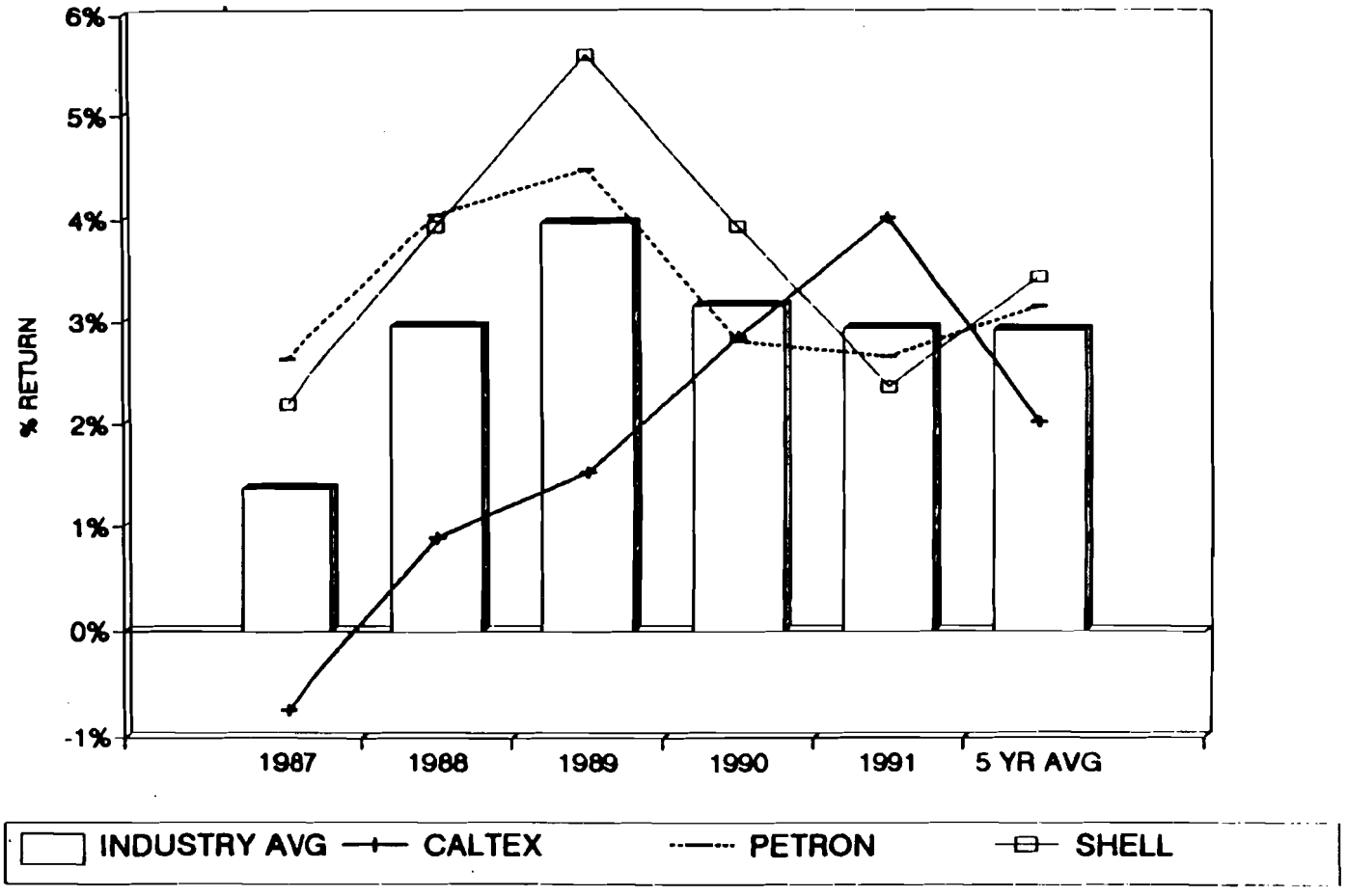


Figure VIII-2

RETURN ON ASSETS

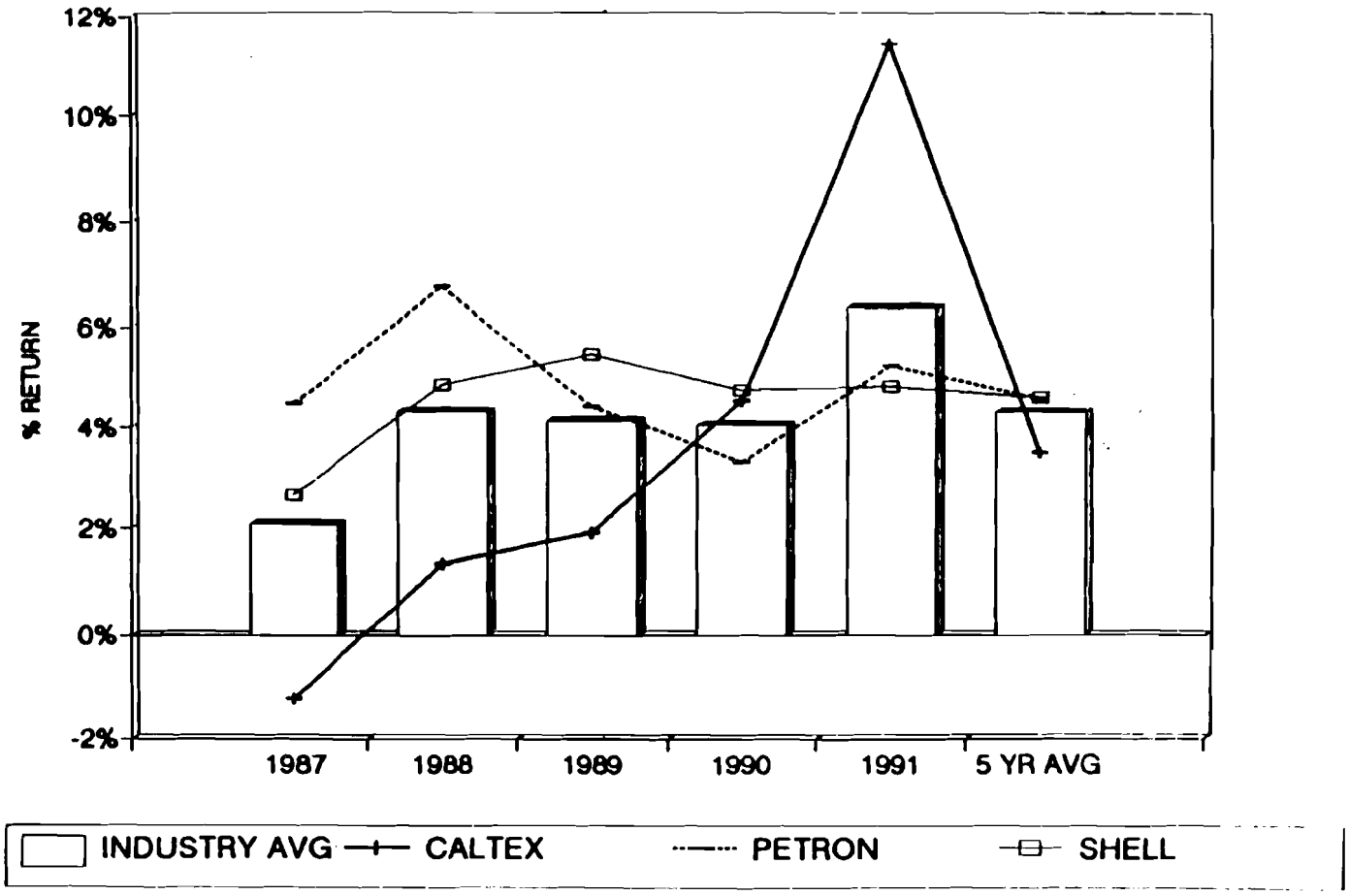


Figure VIII-3

RETURN ON EQUITY

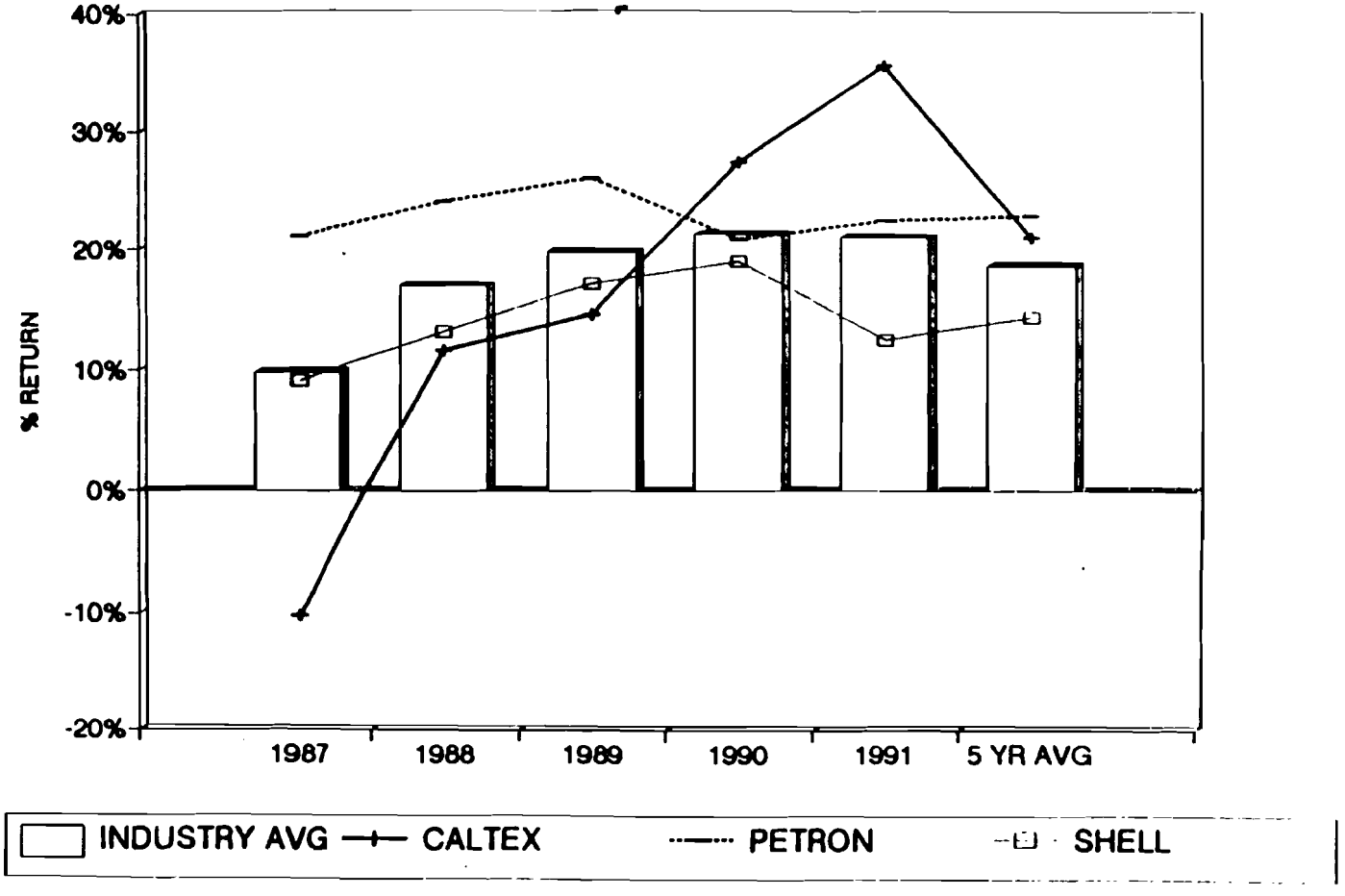


Table IX-1
Caltex Distribution Costs and Recovery

	ERB TRANSHIPMENT COSTS ALLOWANCE				CALTEX ACTUAL COSTS P/L		CALTEX KLITERS 6MO 1992		CALTEX 14APR92 ERB RATES OVER(UNDER) MPEBO		CALTEX 12AUG91 ERB RATES14 OVER(UNDER) MPEBO	
	—WHITE OILS—		—BLACK OILS—									
	14APR92	12AUG91	14APR92	12AUG91	WHITE	BLACK	WHITE	BLACK	WHITE	BLACK	WHITE	BLACK
LUZON												
APARRI	0.2721	0.2610										
BALOGO	0.1950	0.0904	0.0797	0.0840	0.1131	0.0813	0,575	10,763	144	(17)	(90)	29
CALAPAN	0.0903	0.0881			0.3497		0,127		249		312	
LEGASPI	0.1903	0.1601	0.2040	0.2299								
MAMBULAO	0.2510	0.2510			0.3529		0,564		(16)		(871)	
MASINLOC	0.0864	0.1250										
NAVOTAS	0.0633	0.0807										
PALAWAN	0.2968	0.2329										
PANDACAN	0.0633	0.0807	0.0847	0.0809	0.3617	0.0726	500,657	70,991	929	956	(581)	956
PANDACAN-	0.0633	0.0807	0.0847	0.0809								
PASACAO	0.1280	0.1180										
PORO	0.1525	0.1080	0.1747	0.1080	0.2912	0.2912	64,575		(5,660)		(7,936)	
ROSARIO	0.0441	0.0801	0.0436	0.0540								
SAN JOSE	0.1752	0.1450			0.1647		10,403		317		12	
VIRAC	0.2624	0.2460			0.3027		3,939		(156)		(214)	
TOTAL LUZON							652,931	88,754	(3,621)	996	(9,367)	885
VISAYAS												
AMLAN	0.2364	0.1641			0.2912		27,364		(1,360)		(3,470)	
ANIBONG	0.2546	0.2487			0.3039		14,832		(1,860)		(2,006)	
BACOLOD	0.2244	0.1510	0.2175	0.2175	0.2213		34,734		188		(2,442)	
BANTAYAN	0.2908	0.2696			0.1821		1,996		217		174	
BORONGAN	0.2444	0.2186			0.3521		1,108		(20)		(48)	
CULASI	0.2080	0.1649										
ESTANCIA	0.2106	0.1630			0.1800		5,064		254		18	
ILOILO	0.2311	0.1635	0.2756	0.1700	0.1353	0.2258	20,529	857	718	43	(896)	(42)
JIABONG	0.2298	0.2492										
LAPULAPU	0.2138	0.1712	0.2091	0.1891	0.2867	0.2266	98,194	13,402	(2,491)	999	(4,376)	(501)
LAPUS	0.2911	0.1635	0.2756	0.1700								
MACTAN	0.2136	0.1712	0.2091	0.1891								
MALITBOG	0.2664	0.2713			0.3192		1,024		(53)		(46)	
MANDAUE	0.2138	0.1712	0.2091	0.1891								
MASBATE	0.2499	0.1956			0.3579		4,299		223		(182)	
ORMOC	0.2652	0.1987										
SAN ISIDRO	0.2087	0.1687			0.2534		7,628		199		(579)	
TACLOBAN	0.2546	0.2487										
TAGBILARAN	0.2290	0.1906										
TOTAL VISAYAS							176,860	14,259	(4,238)	862	(14,251)	(543)
MINDANAO												
BASILAN	0.2402	0.1800			0.2439		0,552		31		(379)	
BUTUAN	0.2179	0.2179			0.3[illegible]		10,495		111		(535)	
BUTUAN	0.2729	0.2729			0.3[illegible]		4,836		25		(458)	
CABADBARAN	0.2477	0.1800										
CAGAYAN	0.2404	0.2186	0.3030	0.2727	0.2[illegible]	0.3521	25,750	9,329	(1,294)	(498)	(1,979)	(741)
DADIANGAS	0.2275	0.2275	0.4020	0.3020	0.3[illegible]	0.4567	79,703	7,107	(1,691)	239	(9,079)	(481)
DAVAO	0.3186	0.2707	0.4275	0.3366								
ILIGAN	0.2414	0.1906	0.2067	0.2257	0.2[illegible]		0,247		(101)		(525)	
IPIL/BUTUAN	0.3179	0.2179										
JIMENEZ	0.2298	0.1800			0.2532		14,207		(300)		(1,043)	
NASIPIT	0.2585	0.2002										
PARANG	0.3147	0.2474			0.3[illegible]		12,438		91		(746)	
SASA	0.3188	0.2707	0.4270	0.3366	0.4540	0.3969	62,065	24,732	(2,530)	757	(11,377)	(1,401)
TANDAG	0.4344	0.3034			0.4623		1,943		(29)		(134)	
TURBURAN	0.2979	0.2257										
ZAMBOANGA	0.2798	0.2186	0.3006	0.2906		0.3544						
PIPELINE W	0.0630	0.0807			0.0[illegible]	0.0957						
TOTAL MINDANAO							220,480	41,257	(11,844)	541	(27,240)	(2,719)
							=======	======	======	======	======	======
TOTAL							1,050,161	145,270	(19,704)	2,381	(50,858)	(2,571)
PESO/LITER									(0.018)	0.016	(0.047)	(0.018)

BEST AVAILABLE COPY

Table IX-2
Petron Distribution Costs and Recovery

	ERB TRANSHIPMENT COSTS ALLOWANCE				PETRON	PETRON	PETRON	PETRON	PETRON	PETRON	PETRON	PETRON
	...WHITE OILS...		...BLACK OILS...		ACTUAL COSTS P/L		KLITERS 6MO 1992		14APR92 ERB RATES		12AUG91 ERB RATES14	
	14APR92	12AUG91	14APR92	12AUG91	WHITE	BLACK	WHITE	BLACK	OVER/(UNDER) MPESOS		OVER/(UNDER) MPESO	
	WHITE	WHITE	WHITE	WHITE	WHITE	BLACK	WHITE	BLACK	WHITE	BLACK	WHITE	BLACK
LUZON												
APARRI	0.2721	0.2610			0.2508		23.848		508	0	243	0
BALOGOD	0.1350	0.0994	0.0797	0.0840					0	0	0	0
CALAPAN	0.0803	0.0861							0	0	0	0
LEGAZPI	0.1803	0.1601	0.2048	0.2299		0.3692		1,749	0	(270)	0	(226)
MAMBULAO	0.3510	0.2510							0	0	0	0
MASBINLOC	0.0856	0.1268			0.0939		2.565		(22)	0	88	0
NAVOTAS	0.0633	0.0607			0.0407		62060		1,403	0	1,241	0
PALAWAN	0.2968	0.2329			0.3158		21,558		(410)	0	(1,767)	0
PANDACAN	0.0633	0.0607	0.0847	0.0809	0.0491	0.0478	543,511	203,240	7,718	7,500	6,305	6,727
PANDACAN-	0.0633	0.0607	0.0847	0.0809					0	0	0	0
PASACAO	0.1260	0.1188							0	0	0	0
PORO	0.1525	0.1095	0.1747	0.1088	0.1294		65,740		1,519	0	(1,374)	0
ROSARIO	0.0441	0.0681	0.0436	0.0649	0.0386	0.1362	49,206	3,371	226	(312)	1,407	(240)
SAN JOSE	0.1752	0.1459							0	0	0	0
VIRAC	0.2624	0.2469							0	0	0	0
TOTAL LUZON							768,588	208,360	10,942	6,917	6,123	6,261
VISAYAS												
AMLAN	0.2364	0.1641							0	0	0	0
ANIBONG	0.2566	0.2487							0	0	0	0
BACOLOD	0.2244	0.1510	0.3175	0.2175	0.2447	0.3273	39,100	9,783	(872)	(96)	(3,101)	(1,074)
BANTAYAN	0.2908	0.2696							0	0	0	0
BORONGAN	0.2444	0.2196							0	0	0	0
CULASI	0.2069	0.1649			0.2441		37,902		(1,334)	0	(3,002)	0
ESTANCIA	0.2105	0.1639							0	0	0	0
ILOILO	0.2311	0.1626	0.2756	0.1768	0.2646	0.3426	29,697	10,525	(961)	(707)	(2,927)	(1,747)
JIASONG	0.2268	0.2492			0.2917		12,130		(787)	0	(516)	0
LAPULAPU	0.2139	0.1712	0.2691	0.1891					0	0	0	0
LAPUS	0.2311	0.1629	0.2756	0.1768					0	0	0	0
MACTAN	0.2139	0.1712	0.2691	0.1891					0	0	0	0
MALITBOG	0.2664	0.2713			0.2988		2,369		(53)	0	(41)	0
MANDAUE	0.2139	0.1712	0.2691	0.1891	0.2413	0.2781	75,099	25,374	(2,080)	279	(5,321)	(2,258)
MASBATE	0.2499	0.1556							0	0	0	0
ORMAC	0.2692	0.1987			0.2383		27,488		904	0	(1,034)	0
SAN ISIDRO	0.2987	0.1887							0	0	0	0
TACLOBAN	0.2946	0.2407							0	0	0	0
TAGBILARAN	0.2290	0.1995							0	0	0	0
TOTAL VISAYAS							217,586	46,682	(4,383)	(524)	(15,941)	(5,080)
MINDANAO												
BASILAN	0.2486	0.1860							0	0	0	0
BUTUANG	0.3179	0.2179							0	0	0	0
BUTUAN	0.3728	0.2726							0	0	0	0
CABADBARA	0.2477	0.1999							0	0	0	0
CAGAYAN	0.2404	0.2166	0.3033	0.2727	0.2554	0.3268	39,349	11,288	(590)	(264)	(1,527)	(612)
DADIANGAS	0.3275	0.2275	0.4029	0.3029		0.4543		5,215	0	201	0	(320)
DAVAO	0.3166	0.2707	0.4275	0.3366	0.3463	0.4739		4,591	0	(210)	0	(622)
ILIGAN	0.2414	0.1996	0.2957	0.2257	0.2812	0.2683	9,014	8,298	(359)	(22)	(736)	(354)
IPIL/BUTUANG	0.3179	0.2179							0	0	0	0
JIMENEZ	0.2266	0.1802							0	0	0	0
NASIPIT	0.2585	0.2032			0.2786		19,969		(396)	0	(1,503)	0
PAGADIAN	0.3147	0.2474			0.3406		13,382		(347)	0	(1,247)	0
SASA	0.3166	0.2707	0.4275	0.3366			42,067		13,318	0	11,388	0
TANDAG	0.4344	0.3334							0	0	0	0
TURBURAN	0.2679	0.2287							0	0	0	0
ZAMBOANGA	0.2768	0.2156	0.3806	0.2906	0.2898	0.4255	53,231	1,924	373	(67)	(2,879)	(269)
PIPELINE W	0.0633	0.0607							0	0	0	0
TOTAL MINDANAO							177,062	31,257	11,967	(364)	3,497	(2,167)
							=======	======	======	=======	======	======
TOTALS							1,163,236	286,299	17,965	6,029	(6,321)	(986)
PESO/LITER									0.015	0.021	(0.005)	(0.003)

BEST AVAILABLE COPY

Table IX-3
Shell Distribution Costs and Recovery

	ERB TRANSHIPMENT COSTS ALLOWANCE				SHELL	SHELL	SHELL	SHELL	SHELL	SHELL	SHELL	SHELL
	...WHITE OILS...		...BLACK OILS...		ACTUAL COSTS P/L		KLITERS SMD 1992		14APR92 ERB RATES OVER/(UNDER) MPESO		12AUG91 ERB RATES OVER/(UNDER) MPESO	
	14APR92	12AUG91	14APR92	12AUG91	WHITE	BLACK	WHITE	BLACK	WHITE	BLACK	WHITE	BLACK
LUZON												
APARRI	0.2721	0.2610			0.3293		12.934		(727)		(870)	
BALOGO	0.1350	0.0994	0.0797	0.0840								
CALAPAN	0.0803	0.0861			0.0790		10.764		14		98	
LEGASPI	0.1803	0.1601	0.2040	0.2299	0.1619		71.677		1,318		(129)	
MAMBULAO	0.3510	0.2510										
MASINLOC	0.0856	0.1268										
NAVOTAS	0.0633	0.0607										
PALAWAN	0.2968	0.2329										
PANDACAN	0.0633	0.0607	0.0847	0.0809	0.0621	0.1159	701.187	90.812	841	(2,833)	(982)	(3,178)
PANDACAN-	0.0633	0.0607	0.0847	0.0809		0.0700		124.029		1,823		1,352
PASACAO	0.1290	0.1188			0.1061		17.384		381		221	
PORO	0.1525	0.1085	0.1747	0.1088	0.1647	0.1554	74.962	8.400	(915)	162	(4,213)	(391)
ROSARIO	0.0441	0.0681	0.0436	0.0649								
SAN JOSE	0.1752	0.1458			0.3614							
VIRAC	0.2624	0.2469										
TOTAL LUZON							888.908	223.241	914	(848)	(5,875)	(2,218)
VISAYAS												
AMLAN	0.2364	0.1841			0.1766							
ANIBONG	0.2546	0.2487			0.3270		15.162		(1,067)		(1,187)	
BACOLOD	0.2244	0.1510	0.3175	0.2175	0.1353	0.3089	54.972	3.687	4,998	32	863	(337)
BANTAYAN	0.2908	0.2696										
BORONGAN	0.2444	0.2196										
CULASI	0.2089	0.1649			0.1171							
ESTANCIA	0.2105	0.1639										
ILOILO	0.2311	0.1628	0.2756	0.1768								
JIABONG	0.2268	0.2492			0.2242							
LAPULAPU	0.2128	0.1712	0.2891	0.1891								
LAPUS	0.2311	0.1626	0.2756	0.1768	0.1255		26.774		2,627		993	
MACTAN	0.3139	0.1712	0.2891	0.1891	0.1711	0.2568	47,001	27,273	2,012	881	5	(1,846)
MALITBOG	0.2664	0.2713										
MANDAUE	0.2139	0.1712	0.2891	0.1891								
MASBATE	0.2498	0.1555			0.3439		5.610		(527)		(1,067)	
ORMAC	0.2692	0.1987			0.3140							
SAN ISIDRO	0.2687	0.1987										
TACLOBAN	0.2566	0.2487										
TAGBILARAN	0.2290	0.1996			0.2152		19.266		252		(287)	
TOTAL VISAYAS							167.785	30.960	8,394	913	(670)	(2,183)
MINDANAO												
BASILAN	0.2488	0.1860			0.3046							
BUJUNO	0.3179	0.2179										
BUTUAN	0.3729	0.2729										
CABADBAR	0.2477	0.1963			0.2019		20.341		932		(53)	
CAGAYAN	0.2404	0.2166	0.3039	0.2727	0.1922	0.2530	21.827		1,052		533	
DADIANGAS	0.3275	0.2275	0.4329	0.3329	0.2773							
DAVAO	0.3168	0.2707	0.4275	0.3366								
ILIGAN	0.2414	0.1996	0.2957	0.2257	0.1766	0.3025	15.024	9.920	974	(328)	346	(685)
IPIL/BUJUNO	0.3179	0.2179			0.4509							
JIMENEZ	0.2296	0.1802			0.1800		10.212		478		2	
NASIPIT	0.2585	0.2032										
PARANG	0.3147	0.2474			0.3152							
SASA	0.3166	0.2707	0.4275	0.3366	0.3379	0.5206	50.306	5.806	(1,066)	(540)	(3,375)	(1,068)
TANDAG	0.4344	0.3334										
TUKURAN	0.2979	0.2287			0.2387		13.286		787		(133)	
ZAMBOANGA	0.2756	0.2156	0.3806	0.2906	0.2022							
PIPELINE W	0.0633	0.0607										
TOTAL MINDANAO							130.986	14.725	3,155	(868)	(2,691)	(1,753)
TOTALS							1,187.680	268.926	12,461	(804)	(9,226)	(6,154)
PESO/LITER									0.010	(0.003)	(0.008)	(0.023)

BEST AVAILABLE COPY

Figure IX-1

RECOVERY OF DISTRIBUTION COSTS

6MO-92 VOLUME X(ALLOWANCE-ACTUAL COST)

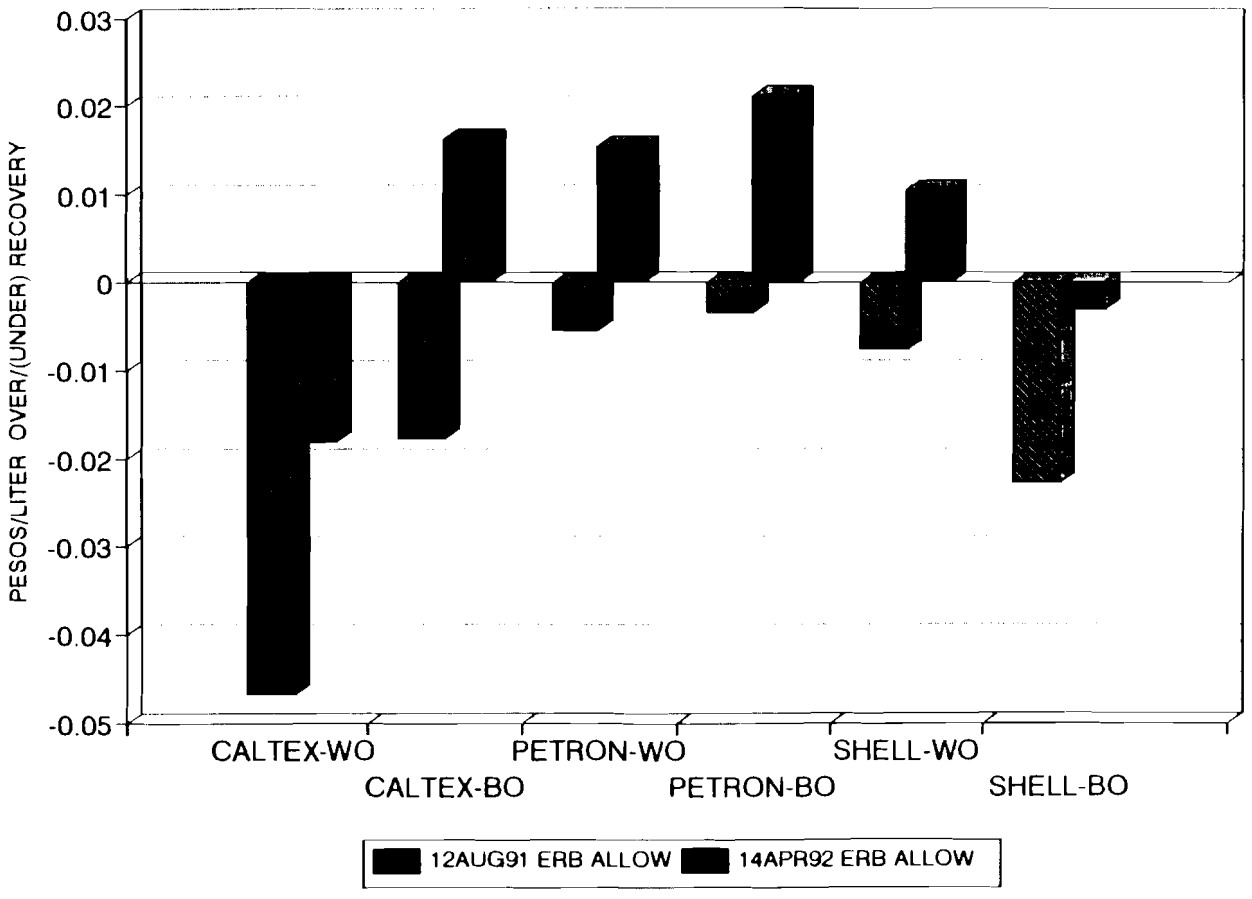


Figure XII-3

LPG TAXES & PRICES - US$/GALLON
RANKED BY PRICE

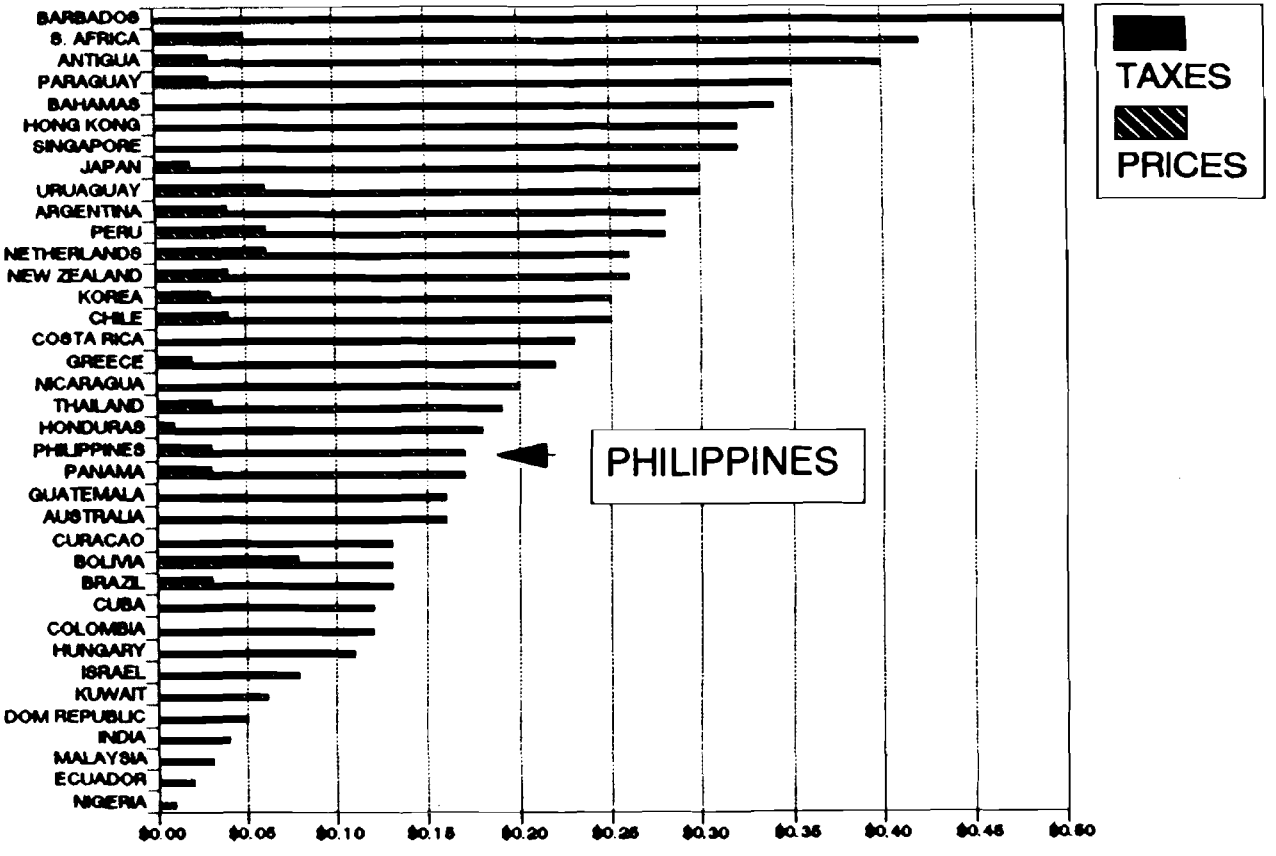


Figure XII-4

REGULAR GASOLINE TAXES & PRICES - US$/GALLON
RANKED BY PRICE

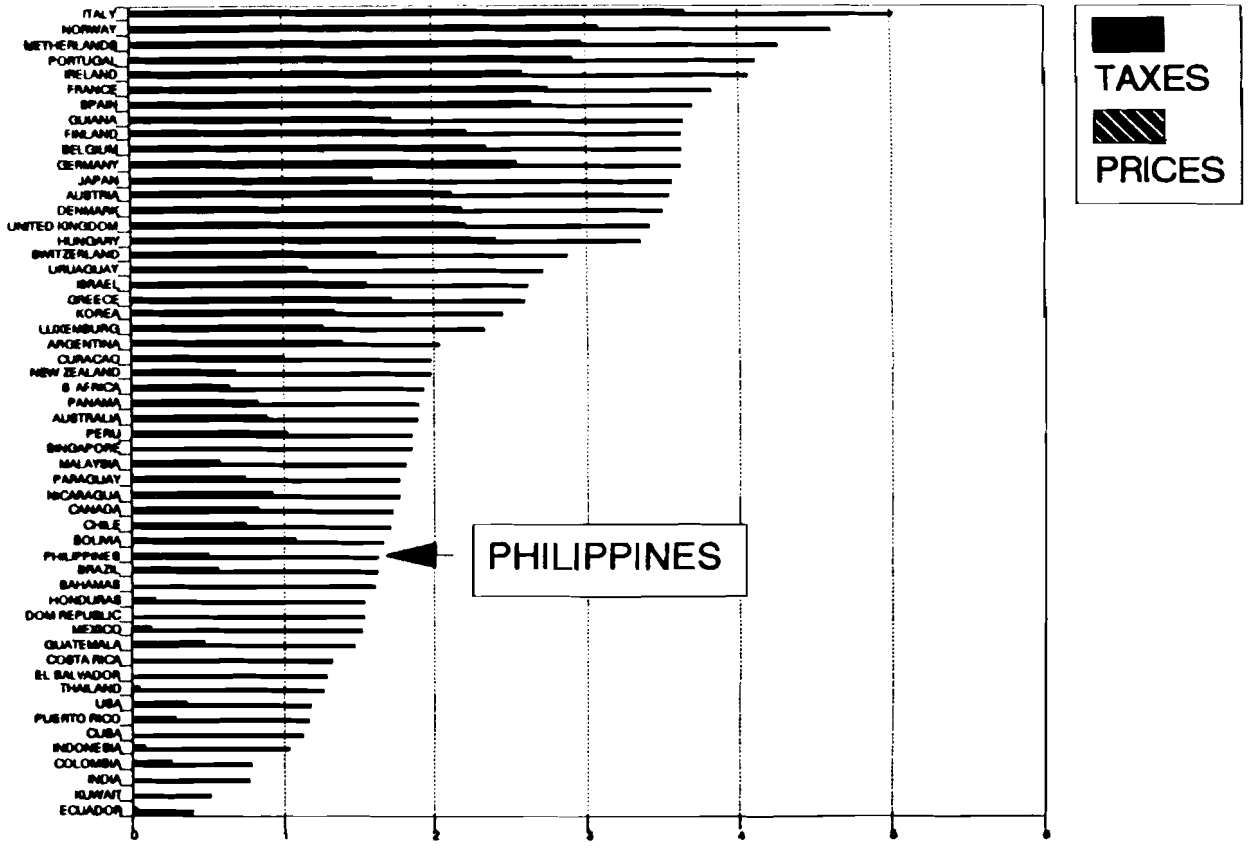


Figure XII-5

PREMIUM GASOLINE TAXES & PRICES - US$/GALLON
RANKED BY PRICE

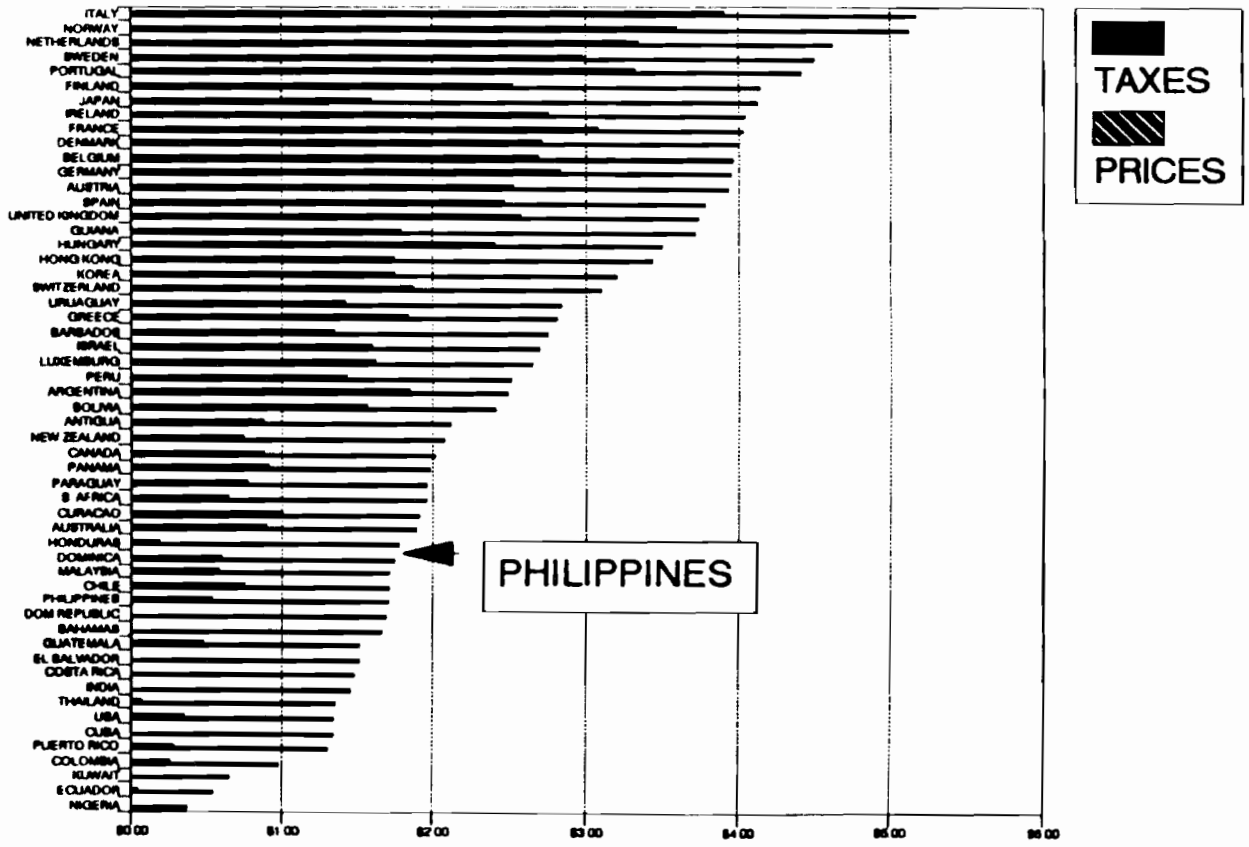


Figure XII-6

DIESEL TAXES & PRICES - US$/GALLON
RANKED BY PRICE

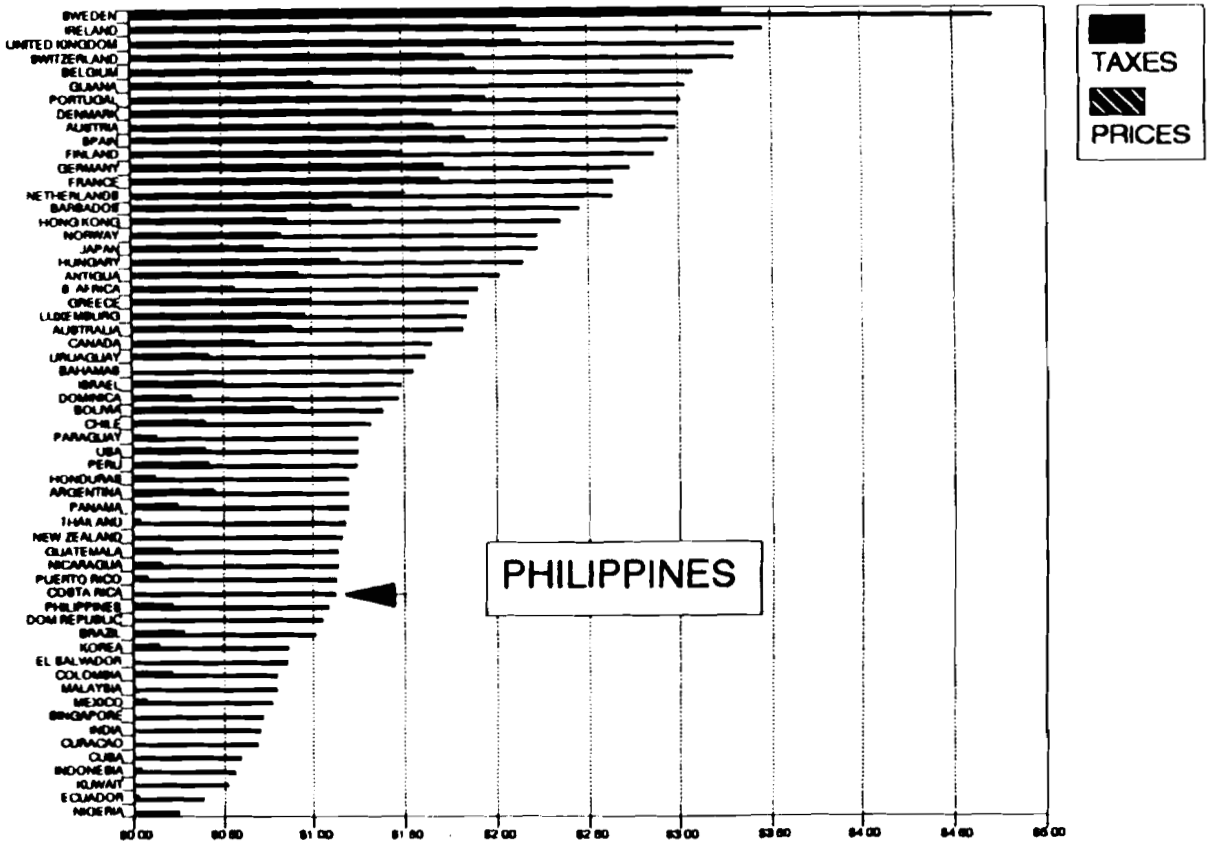


Figure XII-7

JET FUEL TAXES & PRICES - US$/GALLON
RANKED BY PRICE

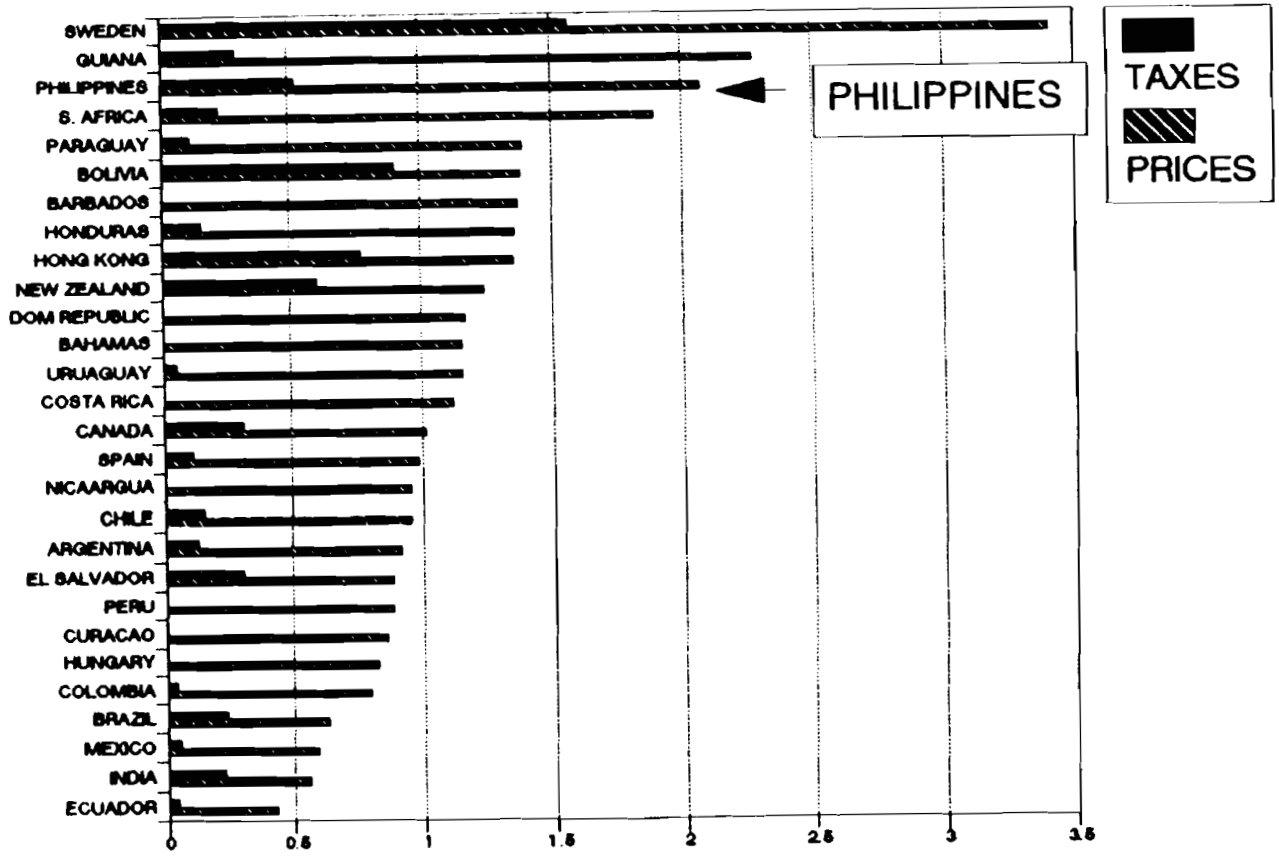


Figure XII-8

KEROSENE TAXES & PRICES - US$/GALLON
RANKED BY PRICE

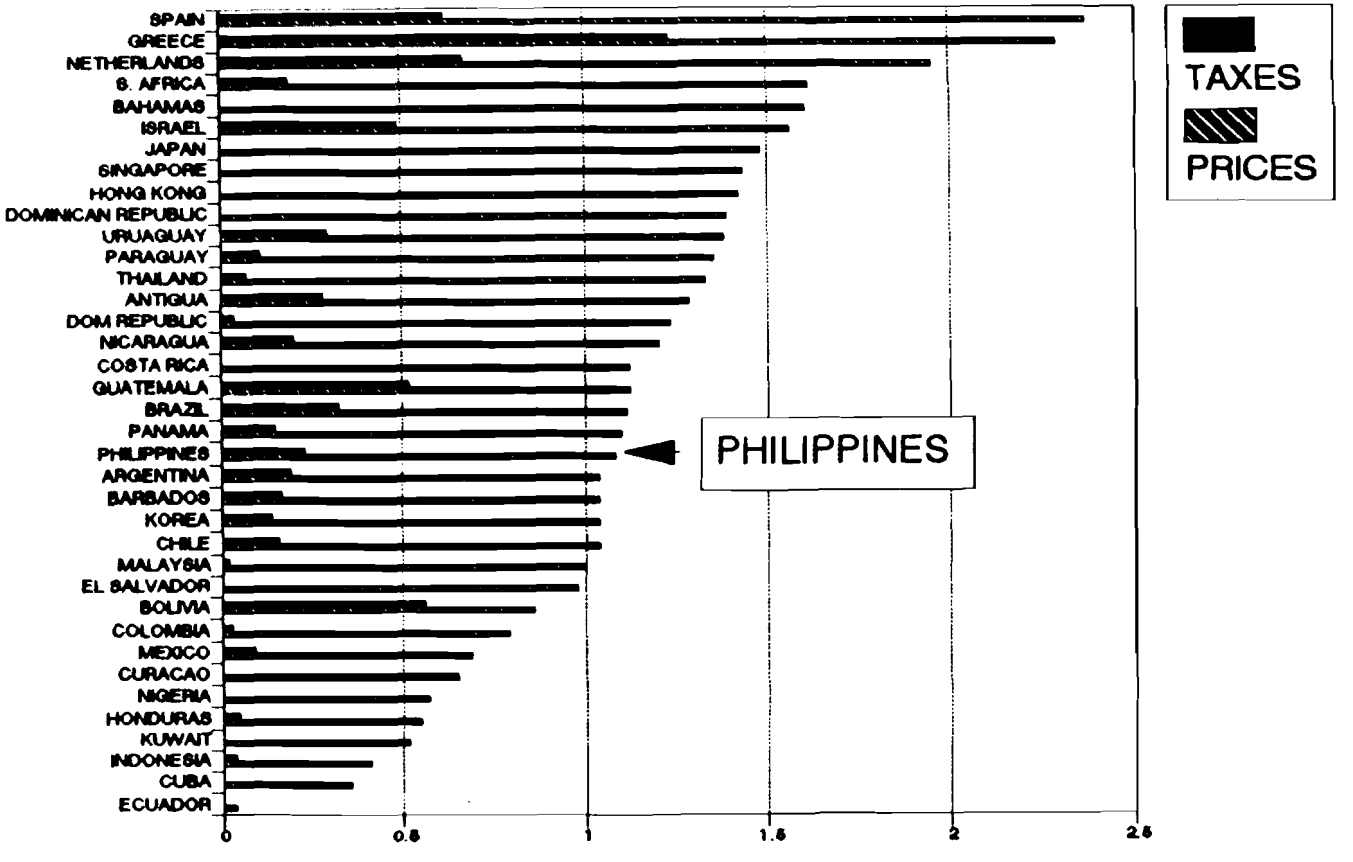
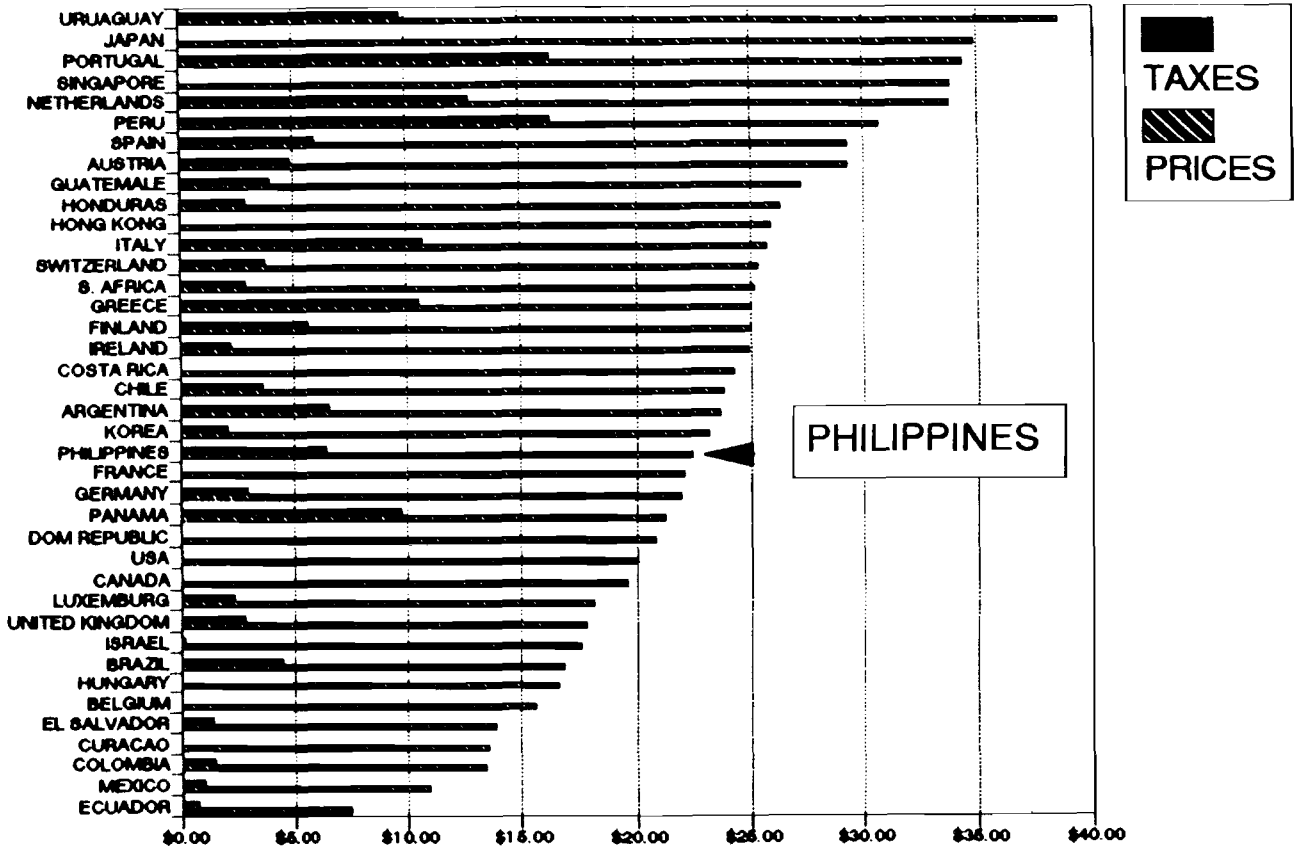


Figure XII-9

HEAVY FUEL TAXES & PRICES - US$/BARREL
RANKED BY PRICE



APPENDIX E:

OFFICE OF ENERGY AND INFRASTRUCTURE

The Office of Energy and Infrastructure

The Agency for International Development's Office of Energy and Infrastructure plays an increasingly important role in providing innovative approaches to solving the continuing energy crisis in developing countries. Three problems drive the Office's assistance programs: high rates of energy use and economic growth accompanied by a lack of energy, especially power in rural areas; severe financial problems, including a lack of investment capital, especially in the electricity sector; and growing energy-related environmental threats, including global climate change, acid rain, and urban air pollution.

To address these problems, the Office of Energy and Infrastructure leverages financial resources of multilateral development banks such as The World Bank and the InterAmerican Development Bank, the private sector, and bilateral donors to increase energy efficiency and expand energy supplies, enhance the role of private power, and implement novel approaches through research, adaption, and innovation. These approaches include improving power sector investment planning ("least-cost" planning) and encouraging the application of cleaner technologies that use both conventional fossil fuels and renewable energy sources. Promotion of greater private sector participation in the power sector and a wide-ranging training program also help to build the institutional infrastructure necessary to sustain cost-effective, reliable, and environmentally-sound energy systems integral to broad-based economic growth.

Much of the Office's strategic focus has anticipated and supports recently-enacted congressional legislation directing the Office and A.I.D. to undertake a "Global Warming Initiative" to mitigate the increasing contribution of key developing countries to greenhouse gas emissions. This strategy includes expanding least-cost planning activities to incorporate additional countries and environmental concerns, increasing support for feasibility studies in renewable and cleaner fossil energy technologies that focus on site-specific commercial applications, launching a multilateral global energy efficiency initiative, and improving the training of host country nationals and overseas A.I.D. staff in areas of energy that can help to reduce expected global warming and other environmental problems.

The Office also helps developing countries speed their economic development through promoting technology cooperation between U.S. suppliers and developing country companies, institutions and governments. This effort involves Business Opportunity Identification to define and analyze the range of commercially viable trade and investment opportunities, technologies, and services that have a positive impact on the environment and are appropriate for developing countries; Venture Promotion to encourage the involvement of the U.S. private sector; Innovative Finance; and Policy Development assistance to developing countries as they pursue policy and regulatory changes to provide market incentives for environmentally beneficial technologies.

To pursue these activities, the Office of Energy and Infrastructure implements the following seven projects: (1) Biomass Energy Systems and Technology Project (BEST); (2) The Renewable Energy Applications and Training Project (REAT); (3) The Private Sector Energy Development Project (PSED); (4) The Energy Training Project (ETP); (5) The Energy Technology Innovation Project (ETIP); (6) The Global Energy and Environmental Management (GLEEM); and (7) The Energy Efficiency Project (EEP).

The Office of Energy and Infrastructure helps set energy policy direction for the Agency, making its projects available to meet generic needs (such as training), and responding to short-term needs of A.I.D.'s field offices in assisted countries.

Further information regarding the Office of Energy and Infrastructure projects and activities is available in our Program Plan, which can be requested by contacting:

Office of Energy and Infrastructure
Bureau for Research and Development
U.S. Agency for International Development
Room 508, SA-18
Washington, D.C. 20523-1810
Tel: (703) 875-4052

BEST AVAILABLE COPY