AN ECONOMIC ANALYSIS OF PROPOSED SCHEDULES FOR REMOVAL OF LEAD ADDITIVES FROM GASOLINE

Prepared for the Environmental Protection Agency under Contract Number 68-02-0050

Bonner & Moore Associates, Inc.

500 Jefferson Bldg. | Cullen Center
Houston, Texas 77002 | (713) 228-0871
Cable: BONMOR

ENVIRONMENTAL PROTECTION AGENCY (EPA)
OFFICE OF AIR PROGRAMS
OFFICE OF TECHNICAL INFORMATION AND PUBLICATIONS
* * *
AIR POLLUTION TECHNICAL INFORMATION CENTER
Research Triangle Park, N. C. 27711

The Office of Technical Information and Publications (OTIP) provides a complete system of technical information and communication activities. The principal element of OTIP charged with the responsibility of technical literature communication is the Air Pollution Technical Information Center (APTIC). APTIC is responsible for the collection and dissemination of all domestic and foreign technical literature related to air pollution. Toward this end, APTIC performs six basic services:

1. Preparation of a monthly bulletin containing informative abstracts of approximately 1000 technical articles. Air Pollution Abstracts has a world-wide distribution of 10,000, with coverage including 1100 domestic and foreign serial publications, patents, government reports, preprints, technical society papers, and proceedings.

2. Provision of literature searches on an individual basis. More than 30,000 technical documents are accessible through APTIC's computer-based information retrieval system.

   Individual literature searches are conducted without charge. In order to receive a highly relevant bibliography one should describe both his area of interest and specific items of concern. A knowledge of one's overall objectives is also valuable. Requests should be directed to the above address, or by telephone to (919) 549-8411 Ext. 2135, or from Government FTS telephones, to (919) 549-2135.

3. Response to inquiries concerning the secondary distribution of federally-produced air pollution-related documents.

4. Preparation for publication of comprehensive bibliographies and state-of-the-art summaries of major air pollution topics.

5. Translation of certain foreign journals cover-to-cover (e.g. the German Staub and the Russian Hygiene and Sanitation) and of selected Russian literature, and individual translation of numerous foreign articles. The former are published through the National Technical Information Service, Springfield, Virginia 22151; the latter, initially for EPA use, are available to the public through the National Translations Center, 35 West 33rd Street, Chicago, Illinois 60616 or through interlibrary loan.

6. Provision of complete conventional library services, primarily for EPA use.

AN ECONOMIC ANALYSIS OF PROPOSED SCHEDULES FOR REMOVAL OF LEAD ADDITIVES FROM GASOLINE

Prepared for the Environmental
Protection Agency under Contract
Number 68-02-0050

25 June 1971

**Bonner & Moore
Associates, Inc.**

500 Jefferson Bldg. | Cullen Center
Houston, Texas 77002 | (713) 228-0871
Cable: BONMOR

RGH-015

TABLE OF CONTENTS

TABLE OF CONTENTS (cont.)

LIST OF ILLUSTRATIONS

LIST OF TABLES

LIST OF TABLES (cont.)

SECTION 1

INTRODUCTION

1.1 PURPOSE

This report is in response to RFP No. EHSD 71-Neg 44, which called for an investigation of the economic impact of various gasoline lead removal schedules. The schedules varied in rapidity of lead removal and in the number of gasoline grades produced. These schedules are shown in Appendix A.

1.2 STUDY TEAM ORGANIZATION

The two-month time limit called for in the RFP necessitated that the study method be simplified as much as possible and that maximum use be made of existing data and data-correlations which were developed by Bonner & Moore from previous studies. Several teams of Bonner & Moore personnel investigated the impact of the schedules on differing facets of the petroleum industry. Their investigations were coordinated into the findings presented in this report.

The Bonner & Moore groups worked closely with an EPA-organized project team composed of Messrs. John O'Conner and Paul Boys from EPA, Michael J. Massey from Carnegie - Mellon University and Lee H. Solomon, a partner of Turner, Mason & Solomon. Mr. Solomon represented the EPA as an independent consultant in the area of petroleum economics.

1.3 REPORT STRUCTURE

Following the brief introductory and background information presented here and in the next section of this report, a summary of conclusions is presented (Section 3), then a discussion of the economic findings from each major schedule studied (Section 4). Following this, Section 5 describes the study methodology in detail.

For simplicity, the terms "TEL" and "lead" have been used throughout this report in referring to lead alkyl additives. These terms should be interpreted as referring to all lead alkyl additives, including TEL and TML. Other petroleum and refining terminology is defined in the Glossary, Appendix F.

SECTION 2

STUDY SCOPE AND METHODOLOGY

2.1 SCOPE

1) *Schedules Studied*

The technical proposal for this study was originally prepared on November 6, 1970, and specified a number of alternate gasoline lead removal schedules for investigation. These schedules represented various rates of lead removal.

Eleven proposal schedules were grouped into two classes, one related to a two-pump marketing system, the other to a three-pump system. In all cases one grade of gasoline was required to be lead free by 1974 to satisfy the needs of any 1975 model cars equipped with exhaust reactors requiring unleaded fuel. The octane level of this grade was originally set at 91 RON in accordance with statements made by automotive manufacturers regarding future automotive requirements. In view of later information obtained from industry sources, the EPA team shifted the basic research octane level to 93, and specified that the impact of a 91 RON requirement be analyzed only indirectly through sensitivity analyses of basic study results. Consequently, the modified contract for EPA called for a study of the following two and three-grade systems†:

- Three-Grade Marketing System

  93 RON Low Lead Fuel (Unleaded After 1973)
  94 RON Regular Grade (Varies from 0 to 3gm of lead/gallon)
  100 RON Premium Grade (Varies from 0 to 3gm of lead/gallon)

- Two-Grade System

  94 RON Low Lead Regular Grade (Unleaded After 1973)
  100 RON Premium Grade (Varies from 0 to 3gm of lead/gallon)

2) *Study Plan*

The study plan called for a feasibility analysis of all eleven schedules and a detailed analysis of those schedules bracketing the feasible ones. The feasibility analysis examined approximate capital

†See Appendix A for a detailed listing of the eleven modified schedules.

costs, pool octane numbers, aromatics concentrations, prime blending component requirements, and year-to-year rates of increase in gasoline volume times octane.

A preliminary selection was made of the slowest and fastest lead removal schedules for 3-grade cases and for 2-grade cases. Spot year detailed analysis of all schedules was also determined to be necessary.

Early results showed that construction industry limits necessitated the definition of two new schedules representing the fastest feasible lead removal for each marketing system. These new schedules were calculated by limiting year-to-year construction at the construction industry capacity for that year.

The study results are hereafter discussed with reference to data on four schedules. They are identified as follows:

Schedule	Gasoline System	Schedule Characteristic
A	3 grade	Gradual removal of lead
L	3 grade	Rapid removal of lead up to construction industry limits
G	2 grade	Gradual removal of lead
M	2 grade	Rapid removal of lead up to construction industry limits

3) *Reference Schedule*

During the 1971-1980 period covered by the RFP, there is an "expected normal growth" in gasoline consumption as well as other products produced by the petroleum industry. Since the industry is presently close to nominal capacity, this growth will call for substantial investment. In order to determine the economic effect of lead removal in this environment, it was necessary to develop a reference schedule. This reference schedule represents the economic consequences of the projected growth, while assuming the operating environment prior to the lead issue; i.e., a basic two-grade gasoline production and distribution system with maximum lead concentrations of 3gm per gallon. The economic effects of differing lead removal patterns were determined by comparison with the reference schedule.

2.2 METHODOLOGY OF STUDY

1) *Study Techniques*

The TEL removal schedules supplied by the Environmental Protection Agency were expressed in terms of maximum allowable TEL content for each gasoline grade in each calendar year through 1980. Initial work of the study involved development of forecasts for light ends products, motor gasoline, jet fuels, petrochemicals, and distillate and heavy fuels. Demand patterns and TEL limitations were imposed upon mathematical refinery models, along with projected industry capacities. Patterns of new equipment construction and refinery operations were determined from the model behavior.

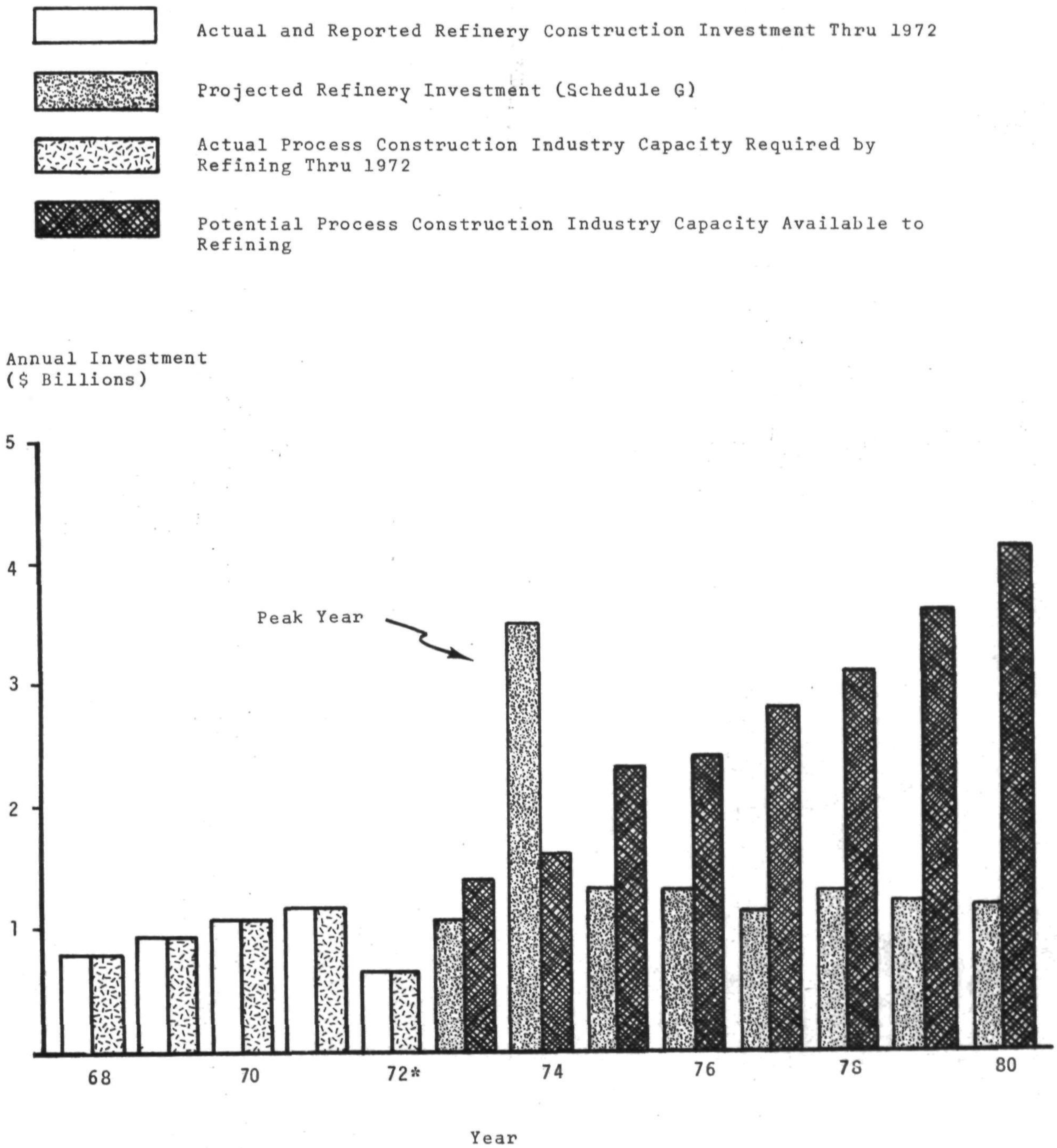
Except for California, refineries of different sizes and geographic locations react similarly to the reduction of allowable levels of TEL in gasoline. Therefore, the refining industry (gasoline producing refineries over 35 thousand barrels per day crude charge) was represented by two linear programming models: one describing a representative California refinery, and the other describing a representative refinery for the rest of the nation. The response of "small" refineries (smaller than 30-35 thousand barrels per day crude charge) differs significantly from the patterns exhibited by the balance of the industry, and these were handled separately by techniques of analysis and extrapolation. Finally, that segment of the refining industry not involved in the manufacture of gasoline was excluded from the modeling system. This segment is characterized by refining facilities which do not include catalytic reformers or catalytic cracking process units.

The basic study technique employed linear programming models because of their inherent ability to seek out an economic optimum among the myriad and conflicting choices of equipment selection, operating conditions, intermediate feedstock allocation, and finished product blending. The results of these case studies served as a basis for further analysis of alternate schedules for conversion to unleaded gasoline.

2) *Peak Year Phenomenon*

Initial study of the various schedules disclosed a disconcerting fact about their effect upon the process construction industry. Rapid lead elimination programs require a major buildup of construction activity to a sharp peak, followed by a shrinkage in construction business. As allowable lead levels are reduced, new refinery equipment must be built to replace the octane quality formerly supplied by lead additives. At this same time, the increasing proportion of the automotive population represented by post-1971 cars (requiring lower octane gasoline) causes a gradual reduction in the average leaded octane level of the gasoline. If lead levels are reduced too rapidly, the refining industry must install equipment sufficient to meet the higher average clear octane requirement of an automotive population while a substantial proportion of pre-1971 cars are still on the road. As time brings about further attrition of the older cars, the average octane requirement of the automotive population will decline, leaving the refining industry with surplus octane-producing facilities and little incentive to order new process construction. These factors can result in a significant process construction industry business decline following the "peak year" and extending over several years. Figure 2-1 shows a typical peak point situation occurring in 1974.

Such a peak point was found to exceed the maximum growth ability forecasted for the process construction industry in all original two-grade schedules and in the more restrictive three-grade schedules. Because of this, two new schedules (L and M) were developed to represent the most rapid lead-reduction programs possible within construction industry capacity.



*Effect of current depressed business.

Figure 2-1. Peak Point Effect of Rapid Lead Reduction

3) *Pre-Investment Cost Adjustments*

When costing the new facilities indicated by the model solutions, no attempt was made to cost the new investment in the specific unit sizes indicated by the model solutions. Instead, investment costs were charged as a pro rata fraction of the cost for average or typical size refinery units of the types under consideration. For example, the typical size of a crude distillation unit was determined to be 70,000 barrels per day. If, for a particular case, the model indicated that 7,000 barrels per day of crude distillation capacity was required, the model refinery would be costed with 1/10th of the construction cost of a 70,000 barrels per day crude unit, not with the estimated construction cost of a 7,000 barrels per day unit. Logically, this might be considered equivalent to interpreting the solution as implying that, in the year in question, 1/10th of the U.S. refineries built "average" 70,000 barrels per day crude units. The installation of new equipment in an individual refinery is, of course, a sharply discontinuous step function when any individual piece of equipment is considered. Consideration of all new construction within the industry tends to smooth this function considerably, however. The 90% of refineries which presumably did not build crude capacity in the example year would have contributed their share to the overall industry construction pattern through the installation of other needed new equipment.

In practice, refining process capacity is planned and installed to recognize and accommodate three-to-five years of growth. Taken as a whole, the capacity growth of the refining sector would appear to be a relatively smooth function with time. For a specific refinery, however, growth would actually occur as discrete changes. For this study, it was assumed that the industry-wide smoothing (via the technique described in the preceding paragraph) tends to reflect an *industry capacity* which results in an *industry excess* no greater than that normally installed.

SECTION 3

SUMMARY OF CONCLUSIONS

3.1 LEAD REMOVAL STRATEGIES

Inherent in the schedules which this study evaluates are certain strategies for implementing lead removal. In summarizing the conclusions it is useful to review what these strategies are. The fundamental objective of lead removal is pollution abatement. Two kinds of automotive pollution are identified. One is the pollution caused by emitting lead salts that are the oxidation products of gasoline lead additives. The other is automotive gaseous emissions that create undesirable levels of carbon monoxide and react photochemically to form smog and ozone. This study is more directly concerned with the economics of the role of gasoline in abating gaseous exhaust pollutants.

The main strategy for lead removal is to create a "new grade" of gasoline. This new grade would have a lower octane rating and would be used in 1971 and later cars that would be designed for it. This new grade would provide the principal medium for facilitating lead removal. Its lower octane makes lead removal substantially less costly than removing lead from today's "conventional grades", namely 94 octane regular and 100 octane premium.

A second strategy is to regulate the lead content of the new grade so that it will be lead free by 1975. In this year it is expected that automobiles equipped with emission abatement devices will be marketed. Current information indicates these devices would be harmed by the presence of lead in gasoline. Thus, the study premises provide that all automobiles manufactured in 1975 and later will use the new grade of gasoline and that this new grade will be produced without lead. It is further premised that owners of cars built between 1971 and 1974 would buy the new grade and conventional regular gasoline in a 50/50 ratio.

These first two strategies insure that all lead emissions will be eliminated from automotive exhausts when the last 1974 automobile has been retired from service. This is the slowest rate of lead elimination that was studied.

A third strategy is employed to further accelerate the rate of lead removal after the first two strategies have been implemented. This strategy involves regulation of the lead content of conventional grades of gasoline. If the maximum lead content of these conventional grades is successively reduced by regulation, then the date at which complete lead removal can be achieved will be earlier than if attrition of pre-1975 automobiles were the only removal mechanism.

3.2 MAJOR CONCLUSIONS

The important data which support study conclusions are summarized in Table 1. Reference is made to comparisons between various numbers in this table throughout the following discussion. The time reference for this table is nominally January 1, 1971. Conclusions about capital expenditures depend on a hypothesis about when a formal lead removal program would be initiated. If it were on January 1, 1972, for example, then the entire expenditure pattern would be shifted by one year.

3.2.1 The Added Per-Gallon Cost of Lead Removal Is Not Large, But The Added Total Cost is Significant

The added cost of removing lead from gasoline was calculated year-by-year for each of the four schedules studied in detail. These added costs are expressed in cents per gallon of total gasoline. Since the kinds of gasoline produced vary from year to year, these costs also vary. However, the range of the highest single-year-added-cost for the four schedules is between 0.23¢ per gallon for Schedule A and 0.90¢ per gallon for Schedule L. This increase is in the order of 5% over present gasoline manufacturing costs. The total cost of lead removal is substantially increased by the necessity to refine more gasoline because cars designed to meet the 1975 air standards will have lower fuel economy. In this study it has been assumed that a 12% loss in fuel economy would characterize cars built in 1975 and later, assuming they are fully equipped with emission abatement devices.

3.2.2 Rapid Lead Removal Requires Substantially More Capital Investment Than Slow Lead Removal (See Figure 3-1)

The third strategy mentioned above, regulating the lead levels of conventional gasoline grades, determines how much faster lead can be removed than if attrition of older cars were the only removal mechanism. Schedules L and M represent the most rapid removal of lead possible within the limits of construction capacity. Schedule A represents the slowest lead removal. Schedule L requires approximately 140% more refinery capital investment than does Schedule A. It should be noted, however, that the lead removal cycle is not totally complete in 1980 for Schedule A. Therefore, study conclusions tend to make A appear to be slightly more economical than it would be when carried through to complete lead removal. In order to assess whether this difference in capital requirement is significant on an industry scale, it is necessary to make some judgment about capital availability for refinery investment. It is beyond the scope of this study to examine this question in detail, but certain observations can be made that provide some perspective to these differences in investment requirements. The slow removal of lead as typified in Schedule A does not produce a peak year effect. Rapid removal of lead, as in Schedule L, produces a marked peak year effect. In Schedule A the average added investment for the refining sector of the oil industry

TABLE 1

STUDY RESULT SUMMARY

CHARACTERISTIC	SCHED-ULES	SCHEDULE YEAR 1971	72	73	74	75	76	80
1. Added Investment (MM$ Above Reference)[1,2]	A	15	-	42	187	122	172	1462
	G	745	187	130	1348	145	183	3226
	L	-	798[3]	344	412	825	844	3456
	M	-	798[3]	344	412	825	1073	3728
2. Total Added Cost (¢ per Gallon Above Reference)	A	0.16	0.20	0.23	0.22	0.22	0.21	0.21
	G	0.19	0.24	0.22	0.56	0.53	0.51	0.36
	L	-	0.48	0.56	0.62	0.85	0.90	0.60
	M	-	0.20	0.24	0.31	0.51	0.68	0.43
3. Percent Lead Reduction (From 1970 Base)	A	4	4	4	4	7	11	44
	G	45	-	-	75	-	-	95
	L	-	62	71	80	92	100	100
	M	-	61	70	78	89	99	100
	Ref	(3)	(18)	(26)	(29)	(33)	(35)	(41)
4. Percent Crude Increase (Above Reference)	A	0.34	0.67	1.37	1.80	1.65	2.42	3.16
	G	0.55	-	-	3.80	-	-	3.93
	L	-	1.77	-	2.76	-	5.03	3.29
	M	-	1.37	-	3.25	-	5.91	3.98
5. Process Industry Construction Activity (% Increase over Prior Year)	A	(4)	16	12	4	8	9	7
	G	(2)	45	37	(23)	(2)	4	7
	L	1	28	18	14	(1)	(12)	7
	M	1	28	18	17	2	(14)	7
6. Clear Pool Octane (RON)	A	88.5	87.7	87.5	87.7	88.3	88.5	90.4
	G	91.8	-	-	93.6	-	-	93.9
	L	-	91.7	-	92.9	-	94.4	93.5
	M	-	91.8	-	93.0	-	94.7	94.2
	Ref	88.4	87.9	-	87.6	-	88.6	87.9
7. Percent Aromatics	Pool A	22	-	-	-	-	24	29
	G	28	-	-	37	-		38
	L	-	27	-	32	-	38	36
	M	-	27	-	31	-	39	38
	Ref	23	22	-	21	-	22	22
	93 A	18	-	-	-	-	32	34
	L	-	21	-	28	-	39	42
	94 A	19	-	-	-	-	20	18
	G	33	-	-	42	-	-	39
	L	-	24	-	29	-	35	21
	M	-	23	-	30	-	40	39
	Ref	23	22	-	21	-	21	21
	100 A	32	-	-	-	-	12	13
	G	18	-	-	11	-	-	11
	L	-	39	-	45	-	53	33
	M	-	38	-	37	-	37	33
	Ref	22	24	-	22	-	22	24

[1]Excluding cost for Distribution.
[2]1980 Figures are Cumulative.
[3]Includes 1971 Investment.

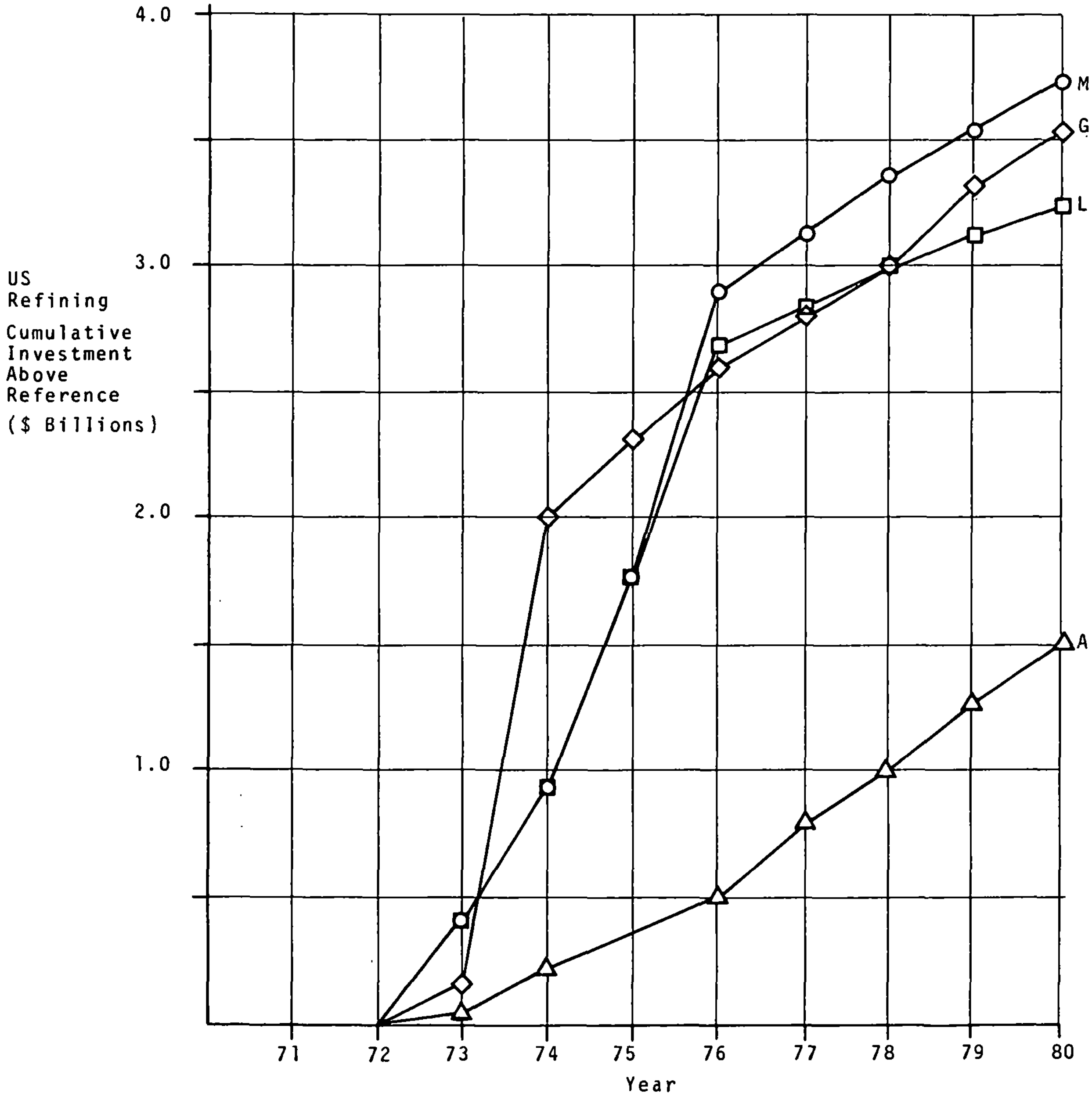


Figure 3-1. Cumulative Investment Requirements for Schedules A, G, L and M

is approximately $150 million dollars annually. For Schedule L the average annual added investment for the critical first four years averages approximately $650 million dollars. It should be emphasized that these are not total annual investments but *added* annual investments to produce unleaded gasoline.

Refinery construction expenditures have historically exhibited a marked cyclical pattern. For this reason it is difficult to say what represents an average annual expenditure. However, if expenditures for the years 1960 through 1972 (projected) were smoothed, an average expenditure rate for 1971 would be in the order of $800 million dollars. During this same time period, refinery expenditures have jumped as much as $300 million dollars in a single year. From this it could be deduced that a $150 million dollar increase in annual refinery expenditures could be accommodated within budget variations which oil companies have employed in the past and therefore be considered within the limits of normal capital resource allocation. On the other hand, an annual expenditure jump of $650 million dollars sustained for 4 years is more than twice as great as previous increases in refining expenditures. It therefore appears that a real capital availability problem could exist.

3.2.3 Lead Removal Will Most Likely Be Accomplished Through Marketing Three Gasolines

A study objective was to determine whether lead removal economics should be based on the assumption of a three-grade or a two-grade gasoline marketing pattern. Results show that slow lead removal as in Schedule A is more economical if accomplished in a three-grade marketing pattern. On the other hand, rapid lead removal is more economically accomplished in a two-grade marketing pattern.

The differences in added gasoline cost between three-grade and two-grade schedules is small enough that other factors might dictate the actual marketing practice. Approximately 65% of the total industry effort required to convert fully to three-grade gasoline marketing has already been made or is committed. A trend back toward two-grade marketing with unleaded gasoline will probably require strong evidence that a consumer preference for this new grade is developing. For purposes of determining the cost consequences of lead elimination, the use of three-grade economic results may be the more realistic.

3.2.4 Construction Industry Capacity Limits The Rate of Lead Removal

The original EPA schedules included several that cannot be met because the construction industry cannot expand rapidly enough to accommodate the added demand for new plants. Detailed examination of required investment patterns also shows that rapid lead removal creates a major business cycle in this industry. The downside of this cycle, occurring after the peak year, would cause unemployment among engineers, technicians, and craftsmen. Schedule G shows the greatest drop in activity, amounting to a business reduction of 23%. Translated into employment figures this would amount to a decrease of about 10,000 jobs.

3.3 ECONOMIC IMPACT

3.3.1 The Consumer

The consumer of motor gasoline will be directly affected in at least two ways by a program to eliminate lead. These are the increased cost of a gallon of unleaded gasoline and the additional volumes of unleaded gasoline required to operate a car which is fully equipped with emission abatement devices. Of these two effects, the loss in fuel economy is by far the greater. This loss in efficiency is not attributed to the unleaded fuel, per se, but to the presence of the emission abatement devices which in turn require the unleaded fuels.

Added costs for unleaded gasoline have been calculated by dividing the total added manufacturing cost by the total quantity of gasoline produced. This does not mean that this added cost would apply only to those motorists purchasing unleaded gasoline. If the total added cost were divided by the unleaded gasoline produced, then these added per-gallon costs would be substantially higher. Also, the assumption is made that the pool of refined gasoline would continue to bring the same average price, so no penalty is calculated due to eliminating the present premium grade. The distribution of added costs might fall on consumers unequally however, depending on how competitive pressures affect the actual pump pricing patterns for premium, regular, and the new grade.

From Table 1 it can be seen that, although added costs vary as much as two-fold, on a year-to-year basis the greatest added cost is only 0.90¢ per gallon. Therefore, the added consumer costs for making unleaded gasoline available would represent an increase in his per-gallon cost at the pump of less than 3%. At the same time it should be recognized that an opportunity for a gasoline price increase, made possible by announcing regulations requiring the sale of unleaded gasolines, might also result in additional price increases being announced at the same time to cover other added refinery costs which, as of this date, have not been passed on to the consumer.

If the consumer pays no more than 3% extra for gasoline produced without lead, then clearly the most significant effect which the consumer will feel is the loss in gasoline efficiency for the post-1975 cars. In this study a representative figure of 12% is used for this loss in efficiency. Therefore, the consumer impact would be the need to buy 12% more gasoline costing as much as 3% more per gallon. This amounts to an overall increase in gasoline cost to the consumer of 15% to 16%.

3.3.2 Impact on the Domestic Petroleum Industry

The most significant impact of a lead removal program on the domestic petroleum industry is the requirement that more capital be spent on refineries over the next 10 years than would be required if the past pattern of expansion and quality change were to continue. It should also be recognized that all refineries built after 1980 to produce unleaded gasoline will continue to be more expensive since they will be producing gasoline of a higher clear octane quality than that produced by today's refineries. In addition, more raw materials must be supplied if future cars meeting the clean air standards sustain the expected fuel efficiency loss.

It is perhaps as important to understand how uncertain the predictions of refinery investment effects are as to note the effects themselves. The flexibility of a modern oil refinery to control the yield of various products makes it virtually impossible to isolate economic effects of quite separate events. All such events tend to have strong interactions. Currently, the planning for future refineries is complicated by three major uncertainties. One of these is the question of unleaded gasoline requirements, the subject of this study. Another is the potential requirement to produce very low sulphur content fuels. The third uncertainty derives from future changes in both the crude oil import regulations and the regulations regarding importation of heavy fuel oils. The outcome of deliberations on each of these points can affect the refining industry. It should be particularly noted that each of these programs may require large capital expenditures when capital availability in the oil industry is of critical concern.

From an operating standpoint,refineries will need to modify their processes to produce more aromatics. The technology to do this is widely used and will simply be more extensively employed.

In addition to the refining sector, that part of the oil industry concerned with distribution and sale of gasoline would also be affected by an unleaded gasoline program. In calculating these effects, an important assumption has been made that the regulation of lead content for unleaded gasolines would not require a completely different mode of operation in distribution than exists at present. This would not be possible if, for example, unleaded gasoline were required to be absolutely free of contamination from leaded fuels. If this were the case, then segregated systems for handling unleaded fuels would be required and these costs would substantially exceed those that have been calculated in this study. This qualification would obviously no longer apply after the transition period had been completed and the only gasoline grades being sold were unleaded.

The impact of an unleaded gasoline program on gasoline distribution is significant only when it is required to sell an extra grade of gasoline. In this study two marketing plans have been examined. One is a conventional two-grade marketing system in which the new grade would be produced at regular gasoline octane and the normal regular grade would be dropped. The other involves adding the new grade to an existing two-grade structure.

The cost for converting the entire U.S. gasoline distribution and marketing system to three grades is estimated at $1.294 billion dollars†. This investment is required for Schedules A and L. In fact, however, many of the major U.S. marketers either market three grades or have scheduled the construction of facilities to permit nation-wide three-grade marketing.

3.3.3 Impact on the Process Construction Industry

The U.S. capability to build new refinery units poses a hard limit to the rate at which lead can be removed from gasoline. The lead removal program will increase construction business during the 10-year period covered in this study. Accelerating the rate of lead removal potentially creates a business cycle in this industry sector, however. This occurs for the same reasons that give rise to the peak year phenomenon discussed earlier. This peak year phenomenon affects the construction industry by requiring an over-building of octane production facilities prior to the peak year. After the peak year, new construction is virtually limited to increasing crude oil capacity to meet growing demand. Capacity of the more expensive refinery process units, mainly those concerned with conversion and octane upgrading, will exceed requirements for several years as pool octanes decline after the peak year.

The process construction industry obtains business from three major sources. One is refinery construction. Another is chemical plant construction. The third is foreign engineering and construction of both refineries and chemical plants. If construction work from the chemical and foreign sectors follows a predictable pattern of growth and the refinery construction load is added to this base, lead removal according to Schedule L would result in a business cycle of approximately 4-years duration amounting to a business loss of 20% in the first year of the cycle. The slowest rate of lead removal, represented by Schedule A, does not show a peak year effect nor does it show a tendency toward generating a business cycle.

Due to the inherent lag time in building process capacity, i.e., accepted bid to accepted plant, it was assumed in the construction analysis that (a) the 1971 and 1972 capacities could not be significantly altered by decisions made in late 1971, and that (b) the projected refinery investments as reported in the Oil and Gas Journal[26] would serve as a base. Therefore, differences in investment requirements for the schedules studied were assumed to be zero in years 1971 and

---

†Lower estimates of this figure have been published but appear not to include all the cost components determined in this study.

1972. Actually, construction wiich will permit increasing gasoline octane has been announced for 1970 and 1971 in excess of $100 million. The added costs for 1971 and 1972 reflect an estimate of the cost of capacity being presently built which, in total or in part, has been justified for the production of unleaded gasoline.

3.3.4 Impact on Petrochemical Costs

The removal of lead additives from gasoline, according to virtually any of the schedules studied, should not have any significant long-term effect on petrochemical costs. Calculated incremental costs for producing aromatics varied erratically from schedule to schedule without showing any definite pattern. The size of variations was in the ± 10% range. The relatively low octane of the unleaded grade and the expected percentage decline of refinery gasoline yields alleviate the potential problem of rising aromatics cost.

The impact of unleaded gasoline on aromatics costs is very sensitive to pool octane number. If unleaded gasoline octanes were to rise above the 93 level used in this study, a rapid aromatics cost increase would follow.

During the early years of a schedule such as L or M, the aromatics market might become unsettled. During these years aromatics production capacity would be substantially increased. This could result in large spot imbalances between this capacity and aromatics demand. Similar situations have historically led to price instabilities.

The impact of an unleaded gasoline program on the cost of light olefins, such as ethylene and propylene, can be expected to be insignificant for two reasons. The most important reason is that investment costs can be expected to predominate in setting price trends. During the 10-year period encompassed by this study, the traditional olefin feed stocks in the U.S. will be insufficient to meet new demands. Consequently, heavier feeds must be employed in new olefin units, and it is most likely that these heavy feeds will come predominately from gas oils. The value of by-product gas oils from the refinery is not as sensitive to the refinery pool octane as are streams which blend directly into gasoline.

3.3.5 Impact on Leaded Gasoline Composition (See Figures 3-2 and 3-3)

Rapid lead removal schedules require the production and blending into gasoline of more aromatics. Increasing aromatics concentration in gasoline to be used in cars without exhaust reactors (pre-1975 cars) may increase exhaust gas reactivity. Further research on this matter is under way. If the findings of Eccleston and Hurn[31] are confirmed, then the higher aromatics content gasoline will aggravate the photochemical smog problem.

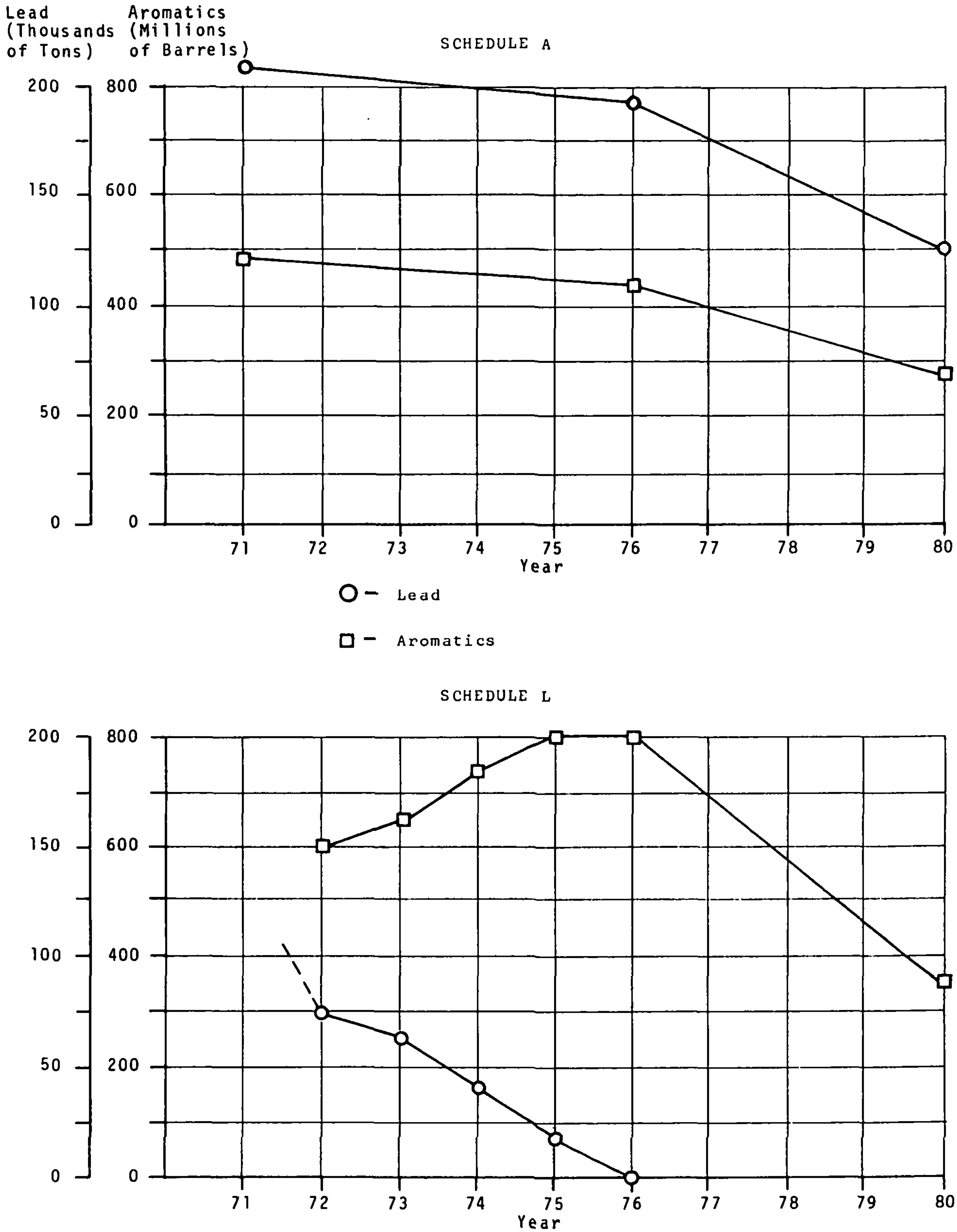


Figure 3-2. Aromatics and Lead Levels for Three-Grade System

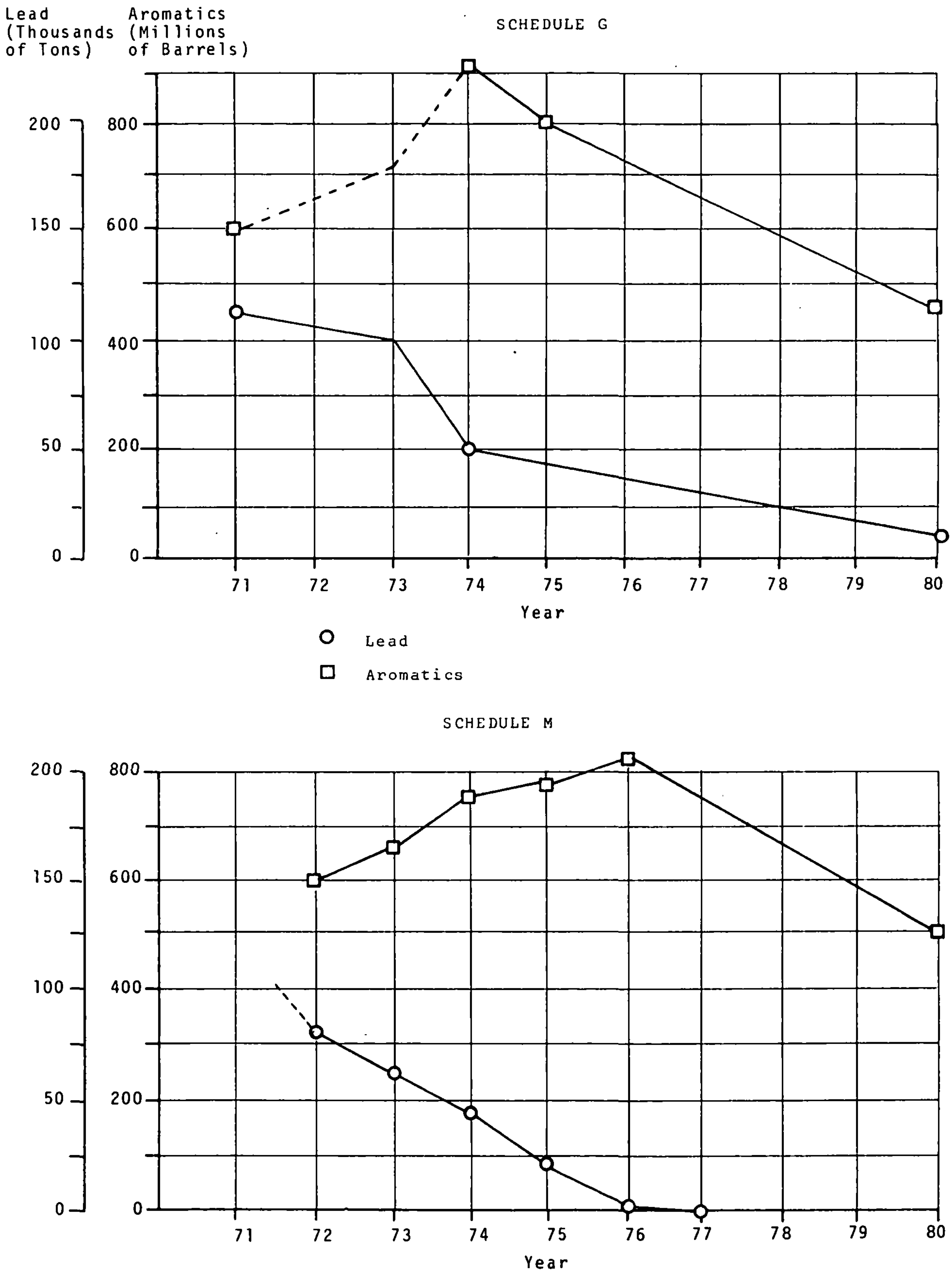


Figure 3-3. Aromatics and Lead Levels for Two-Grade System

3.3.6 Impact on the Small Refiner

Small refiners have an inherent disadvantage in competing with large refiners. This tends to be more pronounced than in other types of manufacturing. Petroleum refining is very capital intensive and economies of scale in building large units substantially affect total manufacturing costs. Table 2 shows how typical investment economics affect refiners of smaller size than the nominal 100,000 barrel refinery used as an example in the study.

TABLE 2

COMPARISON OF INVESTMENT TO CAPACITY RATIOS

(Relative to 100,000 Bbl/Day Refinery)

REFINERY THROUGHPUT BBLS/DAY	RELATIVE UNIT CAPACITY COST
100,000	1.000
50,000	1.32
30,000	1.63
10,000	2.5

Small refineries have operated at a cost disadvantage for many years. During the past twenty years the number of such refineries has dwindled from 155 to 74. The trend of increasing gasoline octane has accentuated this disadvantage, and further octane increases that would be characteristic of a lead removal program would accentuate the differences still further. Certain financial assistance is presently provided the small refiner by the sliding scale feature of the crude oil import quotas and by the provisions that guarantee small refiners access to government petroleum procurements.

A lead removal program will place small refiners in a precarious competitive position as illustrated by data in Table 3. This table shows how added costs for small refiners compared to added costs for the example 100,000 barrel a day refinery in one year of each of the four schedules. If the viability of small refinery operation is to be preserved, further financial assistance will have to be granted to this industry segment.

TABLE 3

INCREASED MANUFACTURING COST VERSUS REFINERY SIZE

(Cents Per Gallon)

THROUGHPUT BBL/DAY	THREE GRADES (1976)		TWO GRADES (1974)	
	A	L	G	M
100,000	0.21	0.90	0.51	0.68
50,000	0.24	1.05	0.59	0.79
30,000	0.26	1.13	0.64	1.18
10,000	0.33	1.40	0.79	1.78

SECTION 4

DETAILED STUDY RESULTS AND CONCLUSIONS

The four schedules selected for intensive study (see Section 2) are discussed in detail in this section of the report. An analysis of the impact upon distribution costs is first presented in paragraph 4.1. Each of the schedules, A, L, G, and M, is described in paragraphs 4.2 through 4.5 in terms of the resulting process conditions, capacity changes and gasoline blending situations for the selected periods.

Paragraph 4.7 presents the results of a series of sensitivity analyses performed on these results. The effect of these schedules upon the small refiner's costs is described in paragraph 4.8 with other implications of lead removal for the small refiner. Paragraph 4.9 describes the impact upon engineering and construction activities. Implications and conclusions about the effects of lead reduction on petrochemicals are presented in paragraph 4.10, and finally, selected results from the California model extrapolations are presented in paragraph 4.11.

In presenting these results, it is convenient to use refinery terminology and to talk about effects in terms of the single refinery model that was employed. Many of the simplifying assumptions employed in modeling are not valid for unique situations, however. Although most of the effects have been extrapolated to represent national quantities, it would be incorrect to extend certain detail and a serious mistake to extend other results. Because the study procedure was designed to measure "industry" effects, it is recommended that the reader neither attempt to draw additional conclusions nor apply these results to specific refining situations.

In order to simplify the description of the gasoline blends for the selected years of each selected schedule, the components have been grouped into stocks that would be produced by a particular kind of process and have thus arrived at 6 categories of gasoline blending stocks. These are cracked stocks (coming from catalytic cracking), alkylate products including propylene, butylene, and pentylene alkylates, aromatic stocks such as reformates and extracted aromatics, light iso-paraffins, (particularly iso-butane, iso-pentane and iso-hexane), paraffinic stocks (made up primarily of virgin gasolines and raffinates) and finally a miscellaneous category including such things as thermally cracked gasolines and visbreaker gasoline. In addition to this stream type composition, the hydrocarbon type analysis of each blend has also been shown.

4.1 LEAD REMOVAL DISTRIBUTION COSTS

This analysis developed cost projections for the gasoline distribution facilities changes which would be required by the various proposed lead removal schedules.

Three-grade lead removal schedules affect the gasoline distribution system because marketing a third grade requires additional tanks and pumps in stations which previously marketed only two grades. Service stations, including other retail businesses which sell gasoline, are the most critical element in the distribution system because of the large number of these installations that may be involved. Other important elements are the bulk stations and terminals and the transportation facilities--pipelines, barges, tankers and tank trucks.

4.1.1 <u>Input Data Description - Sources, Premises</u>[1,2]

There are over 356,000 branded outlets in the United States, of which 222,000 are service stations. A service station receives over half of its sales revenues from petroleum products--other outlets receive less than half. For this analysis the term "service station", or "station", refers to branded outlets in general unless specifically stated otherwise.

A number of companies have already gone to three-grade marketing or have announced their commitment to go to three grades by the end of 1971. Their decision to go to three grades may have been totally independent of lead-removal discussions or may have been made on the assumption that three grades would ultimately be required.

To aid in the projection of costs to accomplish the different lead-removal schedules, petroleum companies have been classified into four groups†:

- Historical three-grade marketers who added a third grade of gasoline before lead removal became an item of concern.
- Three-grade marketers converting primarily in 1970-71 by adding a third, no-lead or low-leaded grade of gasoline.
- Two-grade marketers who will convert to three grades if government regulations favor a three-grade schedule. Marketers who stock two grades and blend the third are in this group.
- Two-grade marketers who will continue to market only two grades, choosing the best two out of three grades if a three-grade schedule is favored.

†Appendix D lists the companies in each of these groups.

1) *Service Station Conversion Cost*

The cost to convert a station to three-grade service is based upon the installation of a new tank and two dispensers with pumps, and the modification of two islands plus associated piping, structural and electrical work. The cost is a weighted average cost per station that considers the number of stations by region and the building cost index for that region. Using these factors, a typical conversion cost for a Gulf Coast marketer, $7,350, becomes $8,030 for the United States as a whole. These figures are derived in the following manner:

Cost of tank (assumed 10,000 gal fiberglass or coated steel)	$1,500
Excavation and backfill	1,400*
Dispensers with suction pumps - 2 per station	1,050
Piping and trenching	1,400*
Conversion of 2 islands	2,000*
Total investment per station (Gulf Coast)	$7,350
*$4800 subtotal adjusted for construction cost variations over U.S. (avg. 14.18% increase)	680
Average investment per station (U.S.)	$8,030

2) *Distribution Terminal Conversion Cost*

The cost to convert a terminal is the cost of a new tank plus associated pumps and piping. These are estimated to require $150,000 per terminal. In general, bulk stations will not need additional tankage.

When converting from leaded to lead-free gasoline, special cleaning of tanks is not considered necessary. Routine and regular cleaning for other purposes, plus a transition period when lead-free fuel will mix with any leaded fuel that may still be in the tanks, are assumed to prevent any unacceptable lead levels in the gasoline after the transition period.

4.1.2 Methods of Analysis and Extrapolation

Group 1 companies are those marketing or having facilities to market three grades of gasoline prior to 1970. These include Gulf, Humble, Standard of California, Standard of Kentucky and a part of Phillips. Group 2 companies have made public announcements about their intentions to market three gasoline grades in 1970-71. The remaining majors are in group 3, and it is assumed that they also will go to three grades if a three-grade schedule is chosen. The remaining independents are in group 4, and it is assumed that they will remain two-grade marketers regardless of the two-grade vs. three-grade decision.

The historical terminal growth data of 1963 through 1967 were projected to 1971, resulting in an estimated 1902 terminals. This number is proportioned to the four groups in the same proportion as the current number of stations in each group. An estimated 40% of the terminals will need additional tankage.

The relation of announced station conversions to the total number of stations for the same companies results in a conversion rate of 65.8% of total stations. This percentage is used to estimate the number of station conversions in groups 1, 2 and 3.

Some two-grade stations may have sufficient dispensers and/or tanks to permit their conversion to three-grade stations at less than the $8,030 per station used in this study. Because an extensive survey would be required to determine the number of such stations, estimated conversion costs may be overstated.

New station construction is assumed to be 4,000 per year. Assuming 65.8% are three-grade facilities, and applying an incremental cost of $8.030 more than two-grade facilities, the additional cost per year is estimated to be more than $21 million. New, three-grade stations are assumed only for four years (1972-75) because after 1975 the projected demand for 100 octane gasoline will fall below 10% of total demand, which should reduce incentive to build additional three-grade stations after this time.

In summary, the estimated investments are as follows:

1)	Group 1 investments (prior to 1970) (not included in schedules)	$510 million
2)	Group 2 investments (already committed)	$746 million

3) Group 3 costs (applies to three-grade schedules) $463 million

4) New construction (applies to three-grade schedules) $ 85 million

Previously Committed Investment
to go to Three-Grade (Group 2) --------- $746 million

Future Investment Required for
Group 3 Companies and New
Construction for Three-Grade
Over Two-Grade Systems ----------------- $548 million

Distribution Facilities
Investment Required for
Marketing Third Grade of
Unleaded Gasoline -------------------- $1294 million

4.2 SCHEDULE A

4.2.1 Description of Schedule

Lead removal Schedule A is for a three-grade marketer in which the lowest octane grade (93.0 RON) is permitted to have 0.5 gm of lead additive per gallon until 1974, at which time all lead is removed from it. The grades corresponding to current regular and premium gasolines are permitted to contain lead throughout the schedule.

4.2.2 Reason for Selecting Schedule A for Study

Schedule A was selected for study because, of all the schedules offered, it obviously had the smallest impact on the refining industry. It represents the minimum cost route (to the refiner) for providing lead-free gasolines for automobiles manufactured post-1974.

4.2.3 Raw Stock Effects

The mildness of this schedule is illustrated by the small difference in total raw material usage compared to the reference schedule. However, this difference increases in the later years of the schedule as the unleaded grade becomes the dominant grade. Table 4 shows the raw stock usage of Schedule A and the reference schedule in terms of crude oil natural gasoline and butanes.

TABLE 4

RAW STOCK REQUIREMENTS FOR SCHEDULE A
(Millions of Barrels/Year)

	1971		1976		1980	
	A	Reference	A	Reference	A	Reference
Normal Butane	68.5	66.6	80.0	79.8	92.7	79.8
Iso-Butane	49.4	48.0	57.7	57.3	66.7	57.4
Natural Gasoline	192.9	192.9	192.9	192.9	192.9	192.9
Sub-Total	310.8	307.5	330.6	330.0	352.3	330.1
Crude Oil	4384.9	4369.7	5548.2	5417.3	6764.0	6557.1
Total	4695.7	4677.2	5878.8	5747.3	7116.3	6887.2
%Increase in Crude	0.34		2.42		3.16	

There are two factors causing the increased need for raw stocks. One, the need for replacement of material converted to low valued fuels, is caused by the more severe processing needed to raise unleaded pool octane. The other is the increased volume of gasoline required to compensate for inefficiencies of low compression ratio engines and for mileage penalties resulting from exhaust gas recycling required to control oxides of nitrogen emissions[30]. Without a complete exploration of the volume-quality effects, it is impossible to identify how these two factors contribute to the total increase in raw stock requirements.

A partial answer to the increased severity contribution can be obtained by comparing the fuel gas and coke productions for Schedule A and the Reference Schedule. These are presented in the next section. The volume increase contribution is reviewed in the volume sensitivity discussion of paragraph 4.7.

4.2.4 By-Product Effects

The increased severity of processing, mentioned above, is further illustrated by the increased production of fuel gas and coke (both variable products). These are shown in Table 5 along with the reference figures.

TABLE 5

BY-PRODUCT PRODUCTION FOR SCHEDULE A

	1971		1976		1980	
	A	Reference	A	Reference	A	Reference
Coke, Thousand Tons/Year	14.3	14.1	24.8	23.8	37.5	36.1
Fuel Gas Trillion BTU/Year	1220	1195	1584	1528	2066	2070

The lower production of fuel gas (Schedule A versus Reference Schedule) in 1980 is a consequence of the relatively mild demand for quality imposed and the volume expansion achieved with hydrocracking. As shown in Tables 8 and 27, the 1980 hydrocracking capacity is an estimated 1.6 million barrels per day compared to 900 thousand barrels per day for the reference schedule case.

4.2.5 Motor Gasoline Blending

Table 7 shows the characteristics and composition of each of the three gasoline grades as well as pertinent pool (composite) properties. It is interesting to note that forcing the 93 grade to be unleaded in 1974 did not require the maximum of 3.0 gm/gal in the remaining grades until 1975. Table 6 presents the TEL levels for each grade for each year.

TABLE 6

TEL CONTENTS OF SCHEDULE A GASOLINES
(gm/gal)

Grade	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
93	0.5	0.5	0.5	0	0	0	0	0	0	0
94	2.1	2.2	2.3	2.5	2.6	2.7	2.7	2.7	2.8	2.8
100	2.3	2.5	2.7	2.8	3.0	3.0	3.0	3.0	3.0	3.0
Pool	2.0	2.0	1.9	1.8	1.7	1.6	1.3	1.1	1.0	0.9

The 1971 pool lead content for Schedule A is in part caused by 6.5% of the pool being the 93 grade. However, both the 94 and 100 grades, neither of which was restricted in lead content, were also low relative to the Reference Schedule (see Table 29). This stems from the lower pool clear octane of Schedule A in 1971 because of the adherence to car population octane requirement for Schedule A and overbuying exhibited by present premium-to-regular ratios (see paragraph 5.3) imposed in the Reference Schedule.

4.2.6 Process Capacity Changes

Table 8 shows the in-plant capacities for major processes for selected years. No overbuilding of capacity was allowed. The added capacities for Schedule A are only slightly greater than those in the reference case (see Table 28). The capacity under 1971, 1976 and 1980 represents the required capacity for that year. For example, crude distillation capacity increased by 3,200,000 B/D to reach the 15,200,000 B/D shown for 1976. This increase for 1972 through 1976 is about 600 B/D per year. It should be noted that the capacities shown do not represent any surplus capacity (except the usual service factor, assumed in this study to be 93%).

TABLE 7

GASOLINE SUMMARY FOR SCHEDULE A

(Sheet 1 of 2)

	1971	1976	1980
93 Octane Blend:			
Volume, 10^9 Gals/Year	6.2	47.4	88.4
TEL, Gm/Gal	0.50	0	0
Leaded RON	93.0	-	-
Leaded MON	85.0	-	-
Clear RON	89.9	93.0	93.0
Clear MON	81.0	85.0	85.0
Stream Composition, %			
Cracked Stocks	48	9	11
Alkylate Products	19	18	16
Aromatic Based	14	50	48
Light Iso-Paraffins	1	9	7
Paraffinic Stocks	11	14	17
Miscellaneous	7	-	1
Hydrocarbon Composition, %			
Paraffins	49	58	55
Olefins	22	5	6
Naphthenes	11	5	5
Aromatics	18	32	34
94 Octane Blend:			
Volume, 10^9 Gals/Year	55.8	50.9	35.9
TEL, Gm/Gal	2.10	2.68	2.77
Leaded RON	94.0	94.0	94.0
Leaded MON	86.0	86.0	86.0
Clear RON	85.6	84.3	83.9
Clear MON	77.8	76.8	76.8
Stream Composition, %			
Cracked Stocks	48	45	59
Alkylate Products	5	-	-
Aromatic Based	17	18	-
Light Iso-Paraffins	-	-	-
Paraffinic Stocks	27	32	38
Miscellaneous	3	5	3
Hydrocarbon Composition, %			
Paraffins	46	46	45
Olefins	22	20	23
Naphthenes	13	14	14
Aromatics	19	20	18

TABLE 7

GASOLINE SUMMARY FOR SCHEDULE A

(Sheet 2 of 2)

	1971	1976	1980
100 Octane Blend:			
Volume, 10^9 Gals/Year	29.8	13.4	4.1
TEL, Gm/Gal	2.29	3.00	3.00
Leaded RON	100.0	100.0	100.0
Leaded MON	93.0	92.2	92.0
Clear RON	94.5	90.8	90.9
Clear MON	84.5	81.9	81.9
Stream Composition, %			
Cracked Stocks	-	38	40
Alkylate Products	25	35	34
Aromatic Based	54	9	8
Light Iso-Paraffins	9	-	-
Paraffinic Stocks	12	18	18
Miscellaneous	-	-	-
Hydrocarbon Composition, %			
Paraffins	66	65	63
Olefins	-	16	17
Naphthenes	2	7	7
Aromatics	32	12	13
Pool:			
Stream Composition, %			
Cracked Stocks	35	29	25
Alkylate Products	11	11	12
Aromatic Based	27	31	34
Light Iso-Paraffins	3	4	5
Paraffinic Stocks	22	23	23
Miscellaneous	2	2	1
Hydrocarbon Composition, %			
Paraffins	52	53	53
Olefins	16	13	11
Naphthenes	10	10	7
Aromatics	22	24	29
RON Clear	88.5	88.5	90.4
MON Clear	80.0	80.9	82.6

TABLE 8

PROCESS CAPACITY REQUIREMENTS FOR SCHEDULE A

	Millions of Barrels/Day		
	1971	1976	1980
Crude Distillation	12.0	15.2	18.5
Coking	0.8	1.4	2.0
Cat Cracking	3.6	3.6	3.6
Hydrocracking	0.6	1.1	1.6
Cat Reforming	2.2	3.0	3.8
Alkylation	0.8	0.9	1.2
Extraction	0.3	1.2	1.5
Isomerization	0.1	0.1	0.1

4.2.7 Cost Effects

Table 9 shows the annual cost for Schedule A relative to the Reference Schedule. Added costs are broken down into refining investment costs, other refining costs and distribution investment costs. These costs are shown both as millions of dollars per year and as cents per gallon of total gasoline.

The "other" refining cost category represents the net effect of increase in operating costs, raw stock costs and product degradation costs plus credits for decreased lead usage and by-products. Included in this cost is the effect of assuming constant value per barrel of gasoline even though the subject case is not the same ratio of premium and regular as in the reference case.

TABLE 9

COST EFFECTS OF SCHEDULE A

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
National Added Costs, MM$/Yr.										
Refining Investment Costs	4	-	15	64	96	141	214	263	326	383
Other Refining Costs	(21)	(69)	(130)	(178)	(214)	(250)	(316)	(353)	(407)	(441)
Total Added Refining Cost	(17)	(69)	(115)	(114)	(118)	(109)	(102)	(90)	(81)	(58)
Added Distribution Costs	170	255	340	340	340	340	340	340	340	340
Total Added Cost	153	186	225	226	222	231	238	250	259	282
National Added Cost, ¢/Gal*										
Refining Investment Costs	-	-	0.02	0.06	0.09	0.13	0.18	0.22	0.26	0.30
Other Refining Costs	(0.03)	(0.08)	(0.13)	(0.17)	(0.19)	(0.22)	(0.26)	(0.29)	(0.32)	(0.35)
Total Added Refining Cost	(0.03)	(0.08)	(0.11)	(0.11)	(0.10)	(0.09)	(0.08)	(0.07)	(0.06)	(0.05)
Added Distribution Costs	0.19	0.28	0.34	0.33	0.32	0.30	0.29	0.28	0.27	0.26
Total Added Cost	0.16	0.20	0.23	0.22	0.22	0.21	0.21	0.21	0.21	0.21

*Using total gasoline demand as a divisor.

4.3 SCHEDULE L

4.3.1 Description of Schedule

Schedule L is a lead removal schedule for a three-grade marketer. It removes lead from all grades of gasoline as quickly as possible within the projected growth capacity of the construction industry. It was developed as a replacement for Schedule E of the original RFP when it was discovered that the amount of process construction implied by Schedule E exceeded the capability of the construction industry. The 93.0 Research Octane grade was required to be clear in 1974.

4.3.2 Reason for Selecting Schedule L for Study

Original study plans called for a detailed study of the extreme ('easiest' and 'most difficult') schedules for the two-grade and three-grade marketers. The effects of intermediate schedules could then be estimated by interpolation. It was anticipated that Schedule E would represent the 'most difficult' schedule for the three-grade marketer. After some preliminary work with Schedule E, it was decided to replace it with a new schedule which did not exceed the estimated capabilities of the construction industry but, at the same time, removed lead from gasoline as rapidly as possible. Schedule L fulfills this criterion.

4.3.3 Raw Stock Effects

Where subjected to the requirement of minimizing TEL in gasoline, the model shows the expected result of requiring more raw stock than in a less restrictive schedule. Both Schedules L and M (discussed later in this section) utilize more crude oil and natural gasoline than either Schedule A or G. Table 10 presents the raw stock requirements for Schedule L as well as those of the reference case. It is apparent from these figures that lead removal requires increased raw stock consumption.

Compared to Schedule A in 1976 (see Table 4), Schedule L requires more crude oil and total raw stock, but not as much natural gasoline and butanes. Even though the reference schedule shows a decline in natural gas liquids utilization, the principal action causing the decrease is the internal production of light hydrocarbons, thus reducing the need for outside purchase. The drop in percentage crude increase in 1980 from 1976 is the result of the decrease in both 94 and 100 octane gasoline grades in that period. Compared to the behavior of Schedule A, Schedule L exhibits the marked effect of producing all gasoline without lead by 1976.

TABLE 10

RAW STOCK REQUIREMENTS FOR SCHEDULE L
(Millions of Barrels/Year)

	1972		1974		1976		1980	
	L	Reference	L	Reference	L	Reference	L	Reference
Normal Butane	92.6	69.8	68.5	81.6	86.1	79.8	92.6	79.8
Iso-Butane	66.7	50.2	49.3	58.7	62.0	57.3	66.7	57.4
Natural Gasoline	192.9	192.9	192.9	192.9	76.5	192.9	162.3	192.9
Sub-total	352.2	312.9	310.7	333.2	224.6	330.0	321.6	330.1
Crude Oil	4634.5	4553.7	5090.9	4954.4	5689.8	5417.3	6772.9	6557.1
Total	4986.7	4866.6	5401.6	5287.6	5914.4	5747.3	7094.5	6887.2
% Increase in Crude	1.77		2.76		5.03		3.29	

4.3.4 By-Product Effects

Table 11 presents a comparison of the fuel gas and coke production for Schedule L and the reference schedule. Because fuel oil demand was held constant, coke production is correlated closely with crude oil run. However, fuel gas produced is related more to overall refinery severity. This is readily apparent when comparing this schedule with both Schedule A (Table 5) and Schedule G (Table 17).

TABLE 11

BY PRODUCT PRODUCTION FOR SCHEDULE L

	1972		1974		1976		1980	
	L	Reference	L	Reference	L	Reference	L	Reference
Coke, MMTons/Year	16.6	15.8	20.8	19.5	26.2	23.8	37.2	36.1
Fuel Gas, 10^{12}BTU/Year	1710	1268	1825	1360	2055	1528	2079	2070

4.3.5 Motor Gasoline Blending

Table 12 presents the lead concentration of each of the three grades for each year examined under Schedule L. The relatively low TEL levels in each grade (as early as 1972) emphasize the fact that TEL reduction becomes increasingly difficult and costly as concentrations approach zero. This is further emphasized where one observes the gradual decrease in TEL levels from 1972 to 1976 when all three grades finally are forced to be made without TEL.

TABLE 12

TEL CONTENTS OF SCHEDULE L GASOLINES*

(gm/gal)

	1972	1973	1974	1975	1976
93 Octane Grade	0.4	0.4	0.0	0.0	0.0
94 Octane Grade	0.9	0.7	0.5	0.2	0.0
100 Octane Grade	0.7	0.3	0.3	0.3	0.0
Pool	0.8	0.6	0.4	0.1	0.0

*All grades unleaded after 1975.

The lower lead levels shown for the 100 grade gasoline compared to the 94 grade gasoline in 1972, 1973 and 1974 result from the fact that premium level octane is derived from components which show less response to lead additives than those which will satisfy the lower quality grades. In 1975, premium shows slightly more lead than the 94 grade because the emphasis is beginning to shift from Research Octane to Motor Octane limitation and the lead response octane level balance shifts slightly.

Table 13 presents the characteristics of Schedule L gasolines for selected years. As can be seen from the pool composition data, there is a strong (inverse) relationship between gasoline aromaticity and TEL content. It also shows the benefit of small amounts of TEL compared to unleaded fuels. It appears that TEL reduction at low concentration requires about 3 barrels of aromatics (replacing 3 Bbls of non-aromatics) per pound of TEL eliminated.

TABLE 13

GASOLINE SUMMARY FOR SCHEDULE L

(Sheet 1 of 2)

	1972	1974	1976	1980
93 Octane Blend:				
Volume, 10^9 Gals/Year	11.9	22.4	47.4	88.4
TEL, gm/gal	0.398	0.0	0.0	0.0
Leaded RON	93.0	-	-	-
Leaded MON	85.0	-	-	-
Clear RON	90.9	93.0	93.0	93.0
Clear MON	81.4	85.0	85.0	85.0
Stream Composition, %				
Cracked Stocks	49	28	38	26
Alkylate Products	11	19	6	5
Aromatic Based	18	26	23	39
Light Iso-Paraffins	13	14	16	3
Paraffinic Stocks	8	13	16	26
Miscellaneous	1	-	1	1
Hydrocarbon Composition, %				
Paraffins	50	54	44	41
Olefins	21	12	11	10
Naphthenes	8	6	6	7
Aromatics	21	28	39	42
94 Octane Blend:				
Volume, 10^9 Gals/Year	55.8	60.8	50.9	35.9
TEL, gm/gal	0.902	0.523	0.0	0.0
Leaded RON	94.0	94.0	-	-
Leaded MON	86.0	86.0	-	-
Clear RON	89.2	91.0	94.0	94.0
Clear MON	80.1	81.5	86.0	86.0
Stream Composition, %				
Cracked Stocks	43	41	23	24
Alkylate Products	9	9	20	31
Aromatic Based	26	29	39	23
Light Iso-Paraffins	-	1	-	16
Paraffinic Stocks	21	20	18	6
Miscellaneous	1	-	-	-
Hydrocarbon Composition, %				
Paraffins	51	47	48	64
Olefins	18	17	13	12
Naphthenes	7	7	4	3
Aromatics	24	29	35	21

TABLE 13

GASOLINE SUMMARY FOR SCHEDULE L

(Sheet 2 of 2)

	1972	1974	1976	1980
100 Octane Blend:				
Volume, 10^9 Gals/Year	26.0	19.3	13.4	4.1
TEL, gm/gal	0.674	0.329	0.0	0.0
Leaded RON	100.0	100.0	-	-
Leaded MON	92.4	92.0	-	-
Clear RON	98.4	99.2	101.4	100.7
Clear MON	87.8	89.6	92.0	92.0
Stream Composition, %				
Cracked Stocks	-	-	-	18
Alkylate Products	27	23	19	40
Aromatic Based	57	54	53	33
Light Iso-Paraffins	9	12	8	-
Paraffinic Stocks	7	9	20	9
Miscellaneous	-	2	-	-
Hydrocarbon Composition, %				
Paraffins	58	51	47	67
Olefins	-	-	-	-
Naphthenes	3	4	-	-
Aromatics	39	45	53	33
Pool:				
Stream Composition, %				
Cracked Stocks	34	32	27	25
Alkylate Products	14	13	14	13
Aromatic Based	32	32	34	34
Light Iso-Paraffins	3	5	7	7
Paraffinic Stocks	16	17	17	20
Miscellaneous	1	1	1	1
Hydrocarbon Composition, %				
Paraffins	52	49	46	48
Olefins	15	13	11	10
Naphthenes	6	6	5	6
Aromatics	27	32	38	36
RON Clear	91.7	92.9	94.4	93.5
MON Clear	82.2	83.7	86.3	85.5

4.3.6 Process Capacity Changes

Table 14 shows the major process plant capacities for the selected years of this schedule. These can be compared to the reference schedule capacities shown in Table 27. Development of Schedule L was restricted to use processes that were shown to be needed in 1976. In other words, the models were not permitted to employ processes in early years that were not selected in 1976 (the peak year). Doing so caused certain justifiable processes to be ignored. As explained in paragraph 5.1, this procedure is believed to be more representative of planning practices than one imposing no look-ahead.

TABLE 14

PROCESS CAPACITY REQUIREMENTS FOR SCHEDULE L

	Millions of Barrels/Day			
	1972	1974	1976	1980
Crude Distillation	13.1	14.3	15.7	18.7
Coking	1.1	1.3	1.7	2.4
Cat Cracking	3.6	3.6	3.6	3.6
Hydrocracking	0.6	0.9	1.6	1.7
Cat Reforming	2.8	3.3	4.1	4.6
Alkylation	1.0	1.0	1.2	1.3
Extraction	0.3	1.0	2.6	2.9
Isomerization	0.2	0.2	0.2	0.2

4.3.7 Cost Effects

Table 15 shows the annual cost effects for Schedule L relative to the Reference Schedule. Added costs are broken down into refining investment costs, other refining costs and distribution investment costs. These costs are shown both as millions of dollars per year and as cents per gallon of total gasoline.

The "other" refining cost category represents the net effect of increase in operating costs, raw stock costs and product degradation costs plus credits for decreased lead usage and by-products. Included in this cost is the effect of assuming constant value per barrel of gasoline even through the subject case pool is not the same ratio of premium and regular as in the reference case. (See paragraph 4.7.4.)

A striking example of the cost of producing low-lead gasolines is shown by comparing 1976 Schedule A (Table 9) with 1976 Schedule L. The cost difference in these two cases is about 770 million dollars annually in domestic refining costs. The difference in TEL consumption between these two cases is about 390 million pounds of TEL annually; thus removal costs about $2.00 per pound of TEL eliminated.

TABLE 15

COST EFFECTS OF SCHEDULE L

	1972	1973	1974	1975	1976	1977	1978	1979	1980
National Added Costs, MM$/Yr.									
Refining Investment Costs	209	299	407	623	844	843	852	881	905
Other Refining Costs	(10)	(79)	(107)	(54)	(182)	(258)	(339)	(406)	(471)
Total Added Refining Costs	199	220	300	569	662	585	513	475	434
Added Distribution Costs	255	340	340	340	340	340	340	340	340
Total Added Cost	454	560	640	909	1002	925	853	815	774
National Added Costs, ¢/Gal*									
Refining Investment Costs	0.21	0.30	0.40	0.58	0.76	0.73	0.71	0.71	0.70
Other Refining Costs	(0.01)	(0.08)	(0.11)	(0.05)	(0.16)	(0.22)	(0.28)	(0.32)	(0.36)
Total Added Refining Costs	0.20	0.22	0.29	0.53	0.60	0.51	0.43	0.39	0.34
Added Distribution Costs	0.28	0.34	0.33	0.32	0.30	0.29	0.28	0.27	0.26
Total Added Cost	0.48	0.56	0.62	0.85	0.90	0.80	0.71	0.66	0.60

*Using total gasoline demand as a divisor.

4.4 SCHEDULE G

4.4.1 Description of Schedule

Lead removal Schedule G is a schedule for a two-grade marketer where the octanes of the grades correspond to the current regular and premium gasolines. The regular (94.0 Research Octane) gasoline is permitted to contain 0.5 gm of lead additive until 1974, at which time the additive must be removed. The premium grade (100.0 Research Octane) is permitted to contain up to 3.0 gm of lead additive throughout the schedule.

4.4.2 Reason for Selecting Schedule G for Study

Schedule G could be seen to have the least impact on the refiners of any of the two-grade schedules offered. This is caused by all others having the same lead schedule on the regular gasoline and equal or lower allowable lead content in premium gasolines.

4.4.3 Raw Stock Effects

Although the least demanding of the two-grade schedules, Schedule G is noticeably more costly and more demanding than Schedule A. The higher crude oil requirements are an indication of this. Table 16 shows the crude and other raw stock requirements along with the comparison figures for the reference schedule.

TABLE 16

RAW STOCK REQUIREMENTS FOR SCHEDULE G

(Millions of Barrels/Year)

	1971		1974		1980	
	G	Reference	G	Reference	G	Reference
Normal Butane	58.1	66.6	72.4	81.6	91.6	79.8
Iso-Butane	41.8	48.0	52.1	58.7	66.0	57.4
Natural Gasoline	192.9	192.9	97.2	192.9	122.2	192.9
Sub-total	292.8	307.5	221.7	333.2	279.8	330.1
Crude Oil	4393.9	4369.7	5142.9	4954.4	6815.1	6557.1
Total	4686.7	4677.2	5364.6	5287.6	7094.9	6887.2
% Increase in Crude	0.55		3.80		3.93	

Comparing the figures in Table 16 with those in Table 4 shows that the two-grade schedules utilize more crude and less natural gasoline and butanes than the three-grade schedules. Directionally, a three-grade schedule was able to utilize slightly more natural gasoline and/or butane purchases because the more severe operations of the two-grade case produced more light hydrocarbons internally, thus requiring less outside purchase.

4.4.4 By-Product Effects

Table 17 presents a comparison of the fuel gas and coke productions for Schedule G and the Reference Schedule.

TABLE 17

BY-PRODUCT PRODUCTION FOR SCHEDULE G

	1971		1974		1980	
	G	Reference	G	Reference	G	Reference
Coke, Million Tons/Year	14.3	14.1	21.2	19.5	37.5	36.1
Fuel Gas, Trillion BTU/Year	1271	1195	1756	1360	2087	2070

A comparison of the 1971 and 1980 fuel gas production of Schedules A and G (Tables 5 and 17) bears out the more severe operations required by two-grade schedules.

4.4.5 Motor Gasoline Blending

Table 18 shows the characteristics and composition of each of the two grades for this schedule. Also shown are the pertinent pool properties. Another indication of the difficulty of reducing TEL in a two-grade environment is shown by the need to use 3 gm/gal in the 100 grade even in 1971. In fact, maximum TEL levels were required for each grade through the full ten years of Schedule G.

TABLE 18

GASOLINE SUMMARY FOR SCHEDULE G

(Sheet 1 of 2)

	1971	1974	1980
94 Octane Blend:			
Volume, 10^9 Gals/Year	62.0	83.2	124.3
TEL, gm/gal	0.5	0.0	0.0
Leaded RON	94.0	-	-
Leaded MON	86.0	-	-
Clear RON	91.7	94.0	94.0
Clear MON	82.6	86.0	86.0
Stream Composition, %			
Cracked Stocks	35	27	24
Alkylate Products	6	9	13
Aromatic Based	34	37	36
Light Iso-Paraffins	6	7	7
Paraffinic Stocks	18	19	19
Miscellaneous	1	1	1
Hydrocarbon Composition, %			
Paraffins	45	42	46
Olefins	15	11	10
Naphthenes	7	5	5
Aromatics	33	42	39
100 Octane Blend:			
Volume, 10^9 Gals/Year	29.8	19.3	4.1
TEL, gm/gal	3.0	3.0	3.0
Leaded RON	100.0	100.0	100.0
Leaded MON	92.0	92.0	92.0
Clear RON	91.3	90.9	90.9
Clear MON	81.8	82.0	82.0
Stream Composition, %			
Cracked Stocks	34	45	45
Alkylate Products	28	36	36
Aromatic Based	19	-	-
Light Iso-Paraffins	-	-	-
Paraffinic Stocks	19	19	19
Miscellaneous	-	-	-
Hydrocarbon Composition, %			
Paraffins	62	64	64
Olefins	14	18	18
Naphthenes	6	7	7
Aromatics	18	11	11

TABLE 18

GASOLINE SUMMARY FOR SCHEDULE G

(Sheet 2 of 2)

	1971	1974	1980
Pool:			
Stream Composition, %			
Cracked Stocks	35	30	24
Alkylate Products	12	13	14
Aromatic Based	30	31	35
Light Iso-Paraffins	4	6	7
Paraffinic Stocks	18	19	19
Miscellaneous	1	1	1
Hydrocarbon Composition, %			
Paraffins	50	46	47
Olefins	15	12	10
Naphthenes	7	5	5
Aromatics	28	37	38
RON Clear	91.8	93.6	93.9
MON Clear	82.6	85.5	85.9

4.4.6 Process Capacity Changes

Table 19 shows the requirements for major process plant capacities for each of the selected years of this schedule. From these figures it is readily apparent that reforming, hydrocracking and, to some extent, alkylation are the processes required to produce the added octane quality of this schedule. This becomes more apparent when compared to A. The requirement to make an unleaded regular gasoline by 1974 shows Schedule G requiring 20% more reforming capacity and almost 40% more hydrocracking as does Schedule A in 1976, two years later. The large increase in extraction separation capacity in 1974 results from needing to purify the aromatics from a large part of the reformate. This effect is apparent when one compares the gasoline pool compositions in Table 18 for years 1971 and 1974. There, it can be seen that the fraction of the pool composed of aromatic stocks is almost constant, while the percentage of aromatics increases about 10%. To accomplish this, heavy raffinate from the extraction processes was recycled to the reformer.

TABLE 19

PROCESS CAPACITY REQUIREMENTS FOR SCHEDULE G

	Millions of Barrels/Day		
	1971	1974	1980
Crude Distillation	12.4	14.1	18.7
Coking	1.0	1.5	2.6
Cat Cracking	3.6	3.6	3.6
Hydrocracking	0.9	1.5	2.0
Cat Reforming	2.8	3.6	4.9
Alkylation	0.9	1.0	1.3
Extraction	0.9	2.0	2.7
Isomerization	0.1	0.1	0.1

4.4.7 Cost Effects

Table 20 shows the annual cost effects for Schedule G relative to the Reference Schedule. Added costs are broken down into refining investment costs and other refining costs. These costs are shown both as millions of dollars per year and as cents per gallon of total gasoline.

TABLE 20

COST EFFECTS OF SCHEDULE G

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
National Added Costs, MM$/Yr.										
Refining Investment Costs	195	244	278	631	669	717	750	755	840	845
Other Refining Costs	(17)	(15)	(56)	(54)	(100)	(149)	(208)	(271)	(332)	(388)
Total Added Refining Costs	178	229	222	577	569	568	542	484	508	457
National Added Costs, ¢/Gal*										
Refining Investment Costs	0.21	0.26	0.28	0.62	0.62	0.64	0.65	0.63	0.68	0.66
Other Refining Costs	(0.02)	(0.02)	(0,06)	(0,06)	(0.09)	(0.13)	(0.18)	(0.23)	0,27	(0.30)
Total Added Refining Costs	0.19	0.24	0,22	0,56	0.53	0.51	0.47	0.40	0,41	0.36

*Using total gasoline demand as a divisor.

The "other" refining cost category represents the net effect of increases in operating costs, raw stock costs and product degradation costs plus credits for decreased lead usage and by-products. Included in this cost is the effect of assuming constant value per barrel of gasoline even though the subject case pool is not the same ratio of premium and regular as in the reference case. (See paragraph 4.7.4.)

Because Schedule G is a two-grade schedule, no added distribution costs are applicable.

4.5 SCHEDULE M

4.5.1 Description of Schedule

Schedule M is a lead removal schedule for a two-grade marketer. It removes lead from both grades as quickly as possible. It was developed as a replacement for Schedule K when it was discovered that the amount of process construction implied by Schedule K exceeded the capability of the construction industry.

4.5.2 Reason for Selecting Schedule M for Study

Original plans for the study included a detailed analysis of Schedule K as the 'most difficult' schedule to be met. After determining that Schedule K could not be met without exceeding the capability of the process construction industry. Schedule M was devised to reduce TEL usage as rapidly as possible while not exceeding the estimated growth potential of the construction industry.

4.5.3 Raw Stock Effects

Table 21 shows the raw stock requirements for Schedule M and for the Reference Schedule. A comparison of Schedule M requirements with those of Schedule L (Table 10) shows a remarkable similarity in raw stock utilization. Again, the two-grade situation shows itself to be less efficient by requiring more (slight in this case) crude as shown in 1976 and compared to Schedule L. It should be noted that Schedule M did not quite achieve totally lead-free gasoline manufacture in 1976 within construction industry limits. It was also impossible to force the 94 RON to be lead free in 1974 without exceeding construction industry capacity.

TABLE 21

RAW STOCK REQUIREMENTS FOR SCHEDULE M

(Millions of Barrels/Year)

	1972		1974		1976		1980	
	M	Reference	M	Reference	M	Reference	M	Reference
Normal Butane	92.7	69.8	69.4	81.6	89.8	79.8	91.8	79.8
Iso-Butane	66.7	50.2	50.0	58.7	64.7	57.3	66.1	57.4
Natural Gasoline	192.9	192.9	167.8	192.9	39.9	192.9	115.3	192.9
Sub-total	352.3	312.9	287.2	333.2	194.4	330.0	273.2	330.1
Crude Oil	4616.3	4553.7	5115.2	4954.4	5737.3	5417.3	6818.1	6557.1
Total	4968.6	4866.6	5402.4	5287.6	5931.7	5747.3	7091.3	6887.2
% Increase in Crude	1.37		3.25		5.91		3.98	

Schedule M shows slightly less raw stock requirement than Schedule L in the early years because it was not possible to reduce TEL contents in the two-grade case as fast as in the three-grade situation. By 1980, Schedule M uses more crude and less light raw stocks to give essentially the same total consumption as that of Schedule L.

4.5.4 By-Product Effects

As with raw stocks, Schedule M shows similar results to Schedule L. Table 22 presents the coke and fuel gas production for Schedule M and for the Reference Schedule. Comparison of these figures with those of Table 11 shows the similarity of behavior of the model under Schedules L and M. Given the objective of minimizing TEL and the constraint of limited investments by year, the difference between a two-grade and a three-grade situation becomes less obvious.

TABLE 22

BY-PRODUCT PRODUCTION FOR SCHEDULE M

	1972		1974		1976		1980	
	M	Reference	M	Reference	M	Reference	M	Reference
Coke, MMTons/Year	15.0	15.8	20.4	19.5	26.8	23.8	37.4	36.1
Fuel Gas, 10^{12}BTU/Year	1612	1268	1824	1360	2148	1528	2087	2070

4.5.5 Motor Gasoline Blending

The primary difference between Schedules L and M is the three versus two-grade gasoline situation. Table 23 presents the characteristics and composition of each of the two grades for Schedule M for the years studied. Table 24 shows TEL levels for 1972 through 1976. Levels for subsequent years are zero. The early reduction to relatively low TEL levels in Schedule M (and as seen in Schedule L), followed by a gradual reduction through the four-year period following 1972, emphasizes the increasing difficulty and cost of removing the last small increment of TEL. Unlike the three-grade situation of Schedule L, Schedule M can not achieve total TEL removal by 1976. For all practical purposes, the 94 octane grade is unleaded in the 1976 case, but the 100 octane grade still shows about 0.1 gm/gal TEL content. In other respects, the gasoline pool for the two

TABLE 23

GASOLINE SUMMARY FOR SCHEDULE M

(Sheet 1 of 2)

	1972	1974	1976	1980
94 Octane Blend:				
Volume, 10^9 Gals/Year	69.4	83.2	98.3	124.3
TEL, gm/gal	0.855	0.444	0.002	0.0
Leaded RON	94.0	94.0	-	-
Leaded MON	86.0	86.0	-	-
Clear RON	89.5	91.7	94.0	94.0
Clear MON	80.3	82.2	86.0	86.0
Stream Composition, %				
Cracked Stocks	44	37	30	25
Alkylate Products	10	9	11	13
Aromatic Based	24	31	34	35
Light Iso-Paraffins	2	5	8	7
Paraffinic Stocks	19	17	16	19
Miscellaneous	1	1	1	1
Hydrocarbon Composition,%				
Paraffins	51	48	44	46
Olefins	19	16	12	10
Naphthenes	7	6	4	5
Aromatics	23	30	40	39
100 Octane Blend:				
Volume, 10^9 Gals/Year	26.0	19.3	13.4	4.1
TEL, gm/gal	0.651	0.235	0.098	0.0
Leaded RON	100.0	100.0	100.0	-
Leaded MON	92.5	92.0	92.0	-
Clear RON	98.5	99.4	99.8	100.7
Clear MON	87.9	90.3	91.3	92.0
Stream Composition, %				
Cracked Stocks	-	-	-	-
Alkylate Products	29	38	40	40
Aromatic Based	56	47	38	33
Light Iso-Paraffins	8	6	4	18
Paraffinic Stocks	7	9	18	9
Miscellaneous	-	-	-	-
Hydrocarbon Composition,%				
Paraffins	59	58	63	67
Olefins	-	-	-	-
Naphthenes	3	5	-	-
Aromatics	38	37	37	33

TABLE 23

GASOLINE SUMMARY FOR SCHEDULE M

(Sheet 2 of 2)

	1972	1974	1976	1980
Pool:				
Stream Composition, %				
Cracked Stocks	34	32	27	24
Alkylate Products	15	14	14	14
Aromatic Based	31	33	35	36
Light Iso-Paraffins	3	5	7	7
Paraffinic Stocks	16	15	16	18
Miscellaneous	1	1	1	1
Hydrocarbon Composition,%				
Paraffins	53	50	46	47
Olefins	14	13	11	10
Naphthenes	6	6	4	5
Aromatics	27	31	39	38
RON Clear	91.8	93.0	94.7	94.2
MON Clear	82.3	83.6	86.6	86.2

minimum TEL schedules show quite similar characteristics. All of the observed differences between Schedules L and M are adequately explained by the three-grade versus two-grade environments.

TABLE 24

TEL CONTENTS OF SCHEDULE M GASOLINE

(gm/gal)

	1972	1973	1974	1975	1976
94 Octane Grade	0.9	0.6	0.4	0.2	trace
100 Octane Grade	0.7	0.4	0.2	0.1	0.1
Pool	0.8	0.5	0.3	0.2	0.01

4.5.6 Process Capacity Changes

Table 25 shows the increases in plant capacities for each of the selected years of this schedule. These can be compared to the capacity figures for Schedule L in Table 13 and the reference capacities shown in Table 27.

TABLE 25

PROCESS CAPACITY REQUIREMENTS FOR SCHEDULE M

	Millions of Barrels/Day			
	1972	1974	1976	1980
Crude Distillation	13.1	14.5	15.8	18.8
Coking	1.0	1.3	1.7	2.4
Cat Cracking	3.6	3.6	3.6	3.6
Hydrocracking	0.5	0.9	1.7	1.9
Cat Reforming	2.6	3.0	3.0	3.7
Alkylation	1.0	1.1	1.2	1.3
Extraction	0.3	0.8	2.7	3.1
Isomerization	0.1	0.1	0.1	0.1

4.5.7 Cost Effects

Table 26 shows the annual cost effects for Schedule M relative to the Reference Schedule. Added costs are broken down into refining investment costs, other refining costs and distribution investment costs. These costs are shown both as millions of dollars per year and as cents per gallon of total gasoline.

The "other" refining cost category represents the net effect of increase in operating costs, raw stock costs and product degradation costs plus credits for decreased lead usage and by-products. Included in this cost is the effect of assuming constant value per barrel of gasoline even though the subject case pool is not the same ratio of premium and regular as in the reference case. (See paragraph 4.7.4.)

TABLE 26

COST EFFECTS OF SCHEDULE M

	1972	1973	1974	1975	1976	1977	1978	1979	1980
National Added Costs, MM$/Yr.									
Refining Investment Costs	209	299	407	623	904	907	921	940	979
Other Refining Costs	(23)	(69)	(96)	(85)	(149)	(201)	(281)	(347)	(429)
Total Added Refining Costs	186	230	311	538	755	706	640	593	550
National Added Costs, ¢/Gal*									
Refining Investment Costs	0.22	0.30	0.40	0.58	0.80	0.79	0.77	0.76	0.75
Other Refining Costs	(0.03)	(0.07)	(0.10)	(0.08)	(0.12)	(0.17)	(0.24)	(0.28)	(0.32)
Total Added Refining Costs	0.19	0.23	0.30	0.50	0.68	0.62	0.53	0.48	0.43

*Using total gasoline demand as a divisor.

4.6 REFERENCE SCHEDULE

As explained in the discussion in paragraph 2.1, a Reference Schedule was defined as a base from which to measure the economic effects of the various lead-removal schedules. This schedule was required to satisfy all product demand forecasts as well as all other operating conditions imposed on the refinery models except for the TEL limitations and attendant gasoline volume increases associated with compression ratio decreases and catalytic exhaust reactor mileage inefficiencies.

Cost consequences of subject case behavior were defined as the differences in investment and cash flows between subject and reference cases. The actual cash flows derived from model results cash flows have not been included in this report because, in themselves, they are meaningless. Only their relative values (to the reference case) can be taken as significant. The absolute magnitude of subject case investments are meaningful because they reflect the load which might be imposed on the construction industry.

All comparisons between subject and reference case behavior have been incorporated into appropriate tables with the exception of gasoline characteristics and process capacity profiles. These aspects of the Reference Schedule are presented in the following tables. Table 28 presents the motor gasoline characteristics of Reference Schedule gasoline,and Table 27 shows major process capacity changes.

TABLE 27

PROCESS CAPACITY REQUIREMENTS FOR REFERENCE SCHEDULE

	Millions of Barrel/Day				
	1971	1972	1974	1976	1980
Crude Distillation	12.0	12.5	13.6	14.8	17.9
Coking	1.0	1.1	1.3	1.5	2.2
Cat Cracking	3.6	3.6	3.6	3.6	3.6
Hydrocracking	0.6	0.6	0.7	0.9	0.9
Cat Reforming	2.4	2.4	2.4	2.6	3.1
Alkylation	0.8	0.8	0.9	0.9	1.0
Extraction	0.3	0.3	0.4	0.5	0.8
Isomerization	0.1	0.1	0.1	0.1	0.1

TABLE 28

GASOLINE SUMMARY FOR REFERENCE SCHEDULE
(Sheet 1 of 2)

	1971	1972	1974	1976	1980
94 Octane Blend:					
Volume, 10^9 Gals/Yr.	56.0	58.0	62.0	65.0	72.0
TEL, gm/gal	1.935	2.262	2.373	2.242	2.168
Leaded RON	94.0	94.0	94.0	94.0	94.0
Leaded MON	86.0	86.0	86.0	86.0	86.0
Clear RON	85.9	85.2	85.1	85.4	85.6
Clear MON	77.7	77.2	77.1	77.2	77.5
Stream Composition, %					
Cracked Stocks	41	42	42	43	44
Alkylate Products	-	0	-	-	-
Aromatic Based	29	26	25	25	23
Light Iso-Paraffins	-	-	-	1	3
Paraffinic Stocks	28	29	29	27	26
Miscellaneous	2	3	4	4	4
Hydrocarbon Composition, %					
Paraffins	46	45	46	46	45
Olefins	18	19	19	19	20
Naphthenes	14	14	14	14	14
Aromatics	22	22	21	21	21
100 Octane Blend:					
Volume, 10^9 Gals/Yr.	35.0	36.0	39.0	41.0	45.0
TEL, gm/gal	2.738	2.794	2.815	2.937	2.690
Leaded RON	100.0	100.0	100.0	100.0	100.0
Leaded MON	92.5	93.1	93.4	93.9	94.5
Clear RON	92.8	92.6	92.2	91.6	91.9
Clear MON	83.3	83.3	84.1	83.7	84.9
Stream Composition, %					
Cracked Stocks	24	20	15	10	-
Alkylate Products	31	30	31	30	30
Aromatic Based	26	30	31	33	43
Light Iso-Paraffins	7	7	8	7	3
Paraffinic Stocks	12	13	15	20	24
Miscellaneous	-	-	-	-	-
Hydrocarbon Composition, %					
Paraffins	62	63	65	66	66
Olefins	10	8	6	4	-
Naphthenes	6	7	8	8	9
Aromatics	22	22	21	22	25
Pool:					
Stream Composition, %					
Cracked Stocks	35	34	32	31	28
Alkylate Products	11	11	11	11	11
Aromatic Based	28	28	28	29	31
Light Iso-Paraffins	3	2	3	3	3
Paraffinic Stocks	22	23	24	24	24
Miscellaneous	1	2	2	2	3

TABLE 28

GASOLINE SUMMARY FOR REFERENCE SCHEDULE

(Sheet 2 of 2)

	1971	1972	1974	1976	1980
Hydrocarbon Composition, %					
Paraffins	52	52	52	52	53
Olefins	15	15	15	14	13
Naphthenes	11	11	12	12	12
Aromatics	22	22	21	22	22
RON Clear	88.4	87.9	87.6	88.6	87.9
MON Clear	79.7	79.4	79.5	79.6	80.0

4.7 SENSITIVITY ANALYSES

The sensitivity of the results of this study to several key assumptions was measured to provide a better understanding of the results, to improve confidence in the results and to provide a means of estimating the effects of varying these assumptions.

Cases were run to test the following:

1) *The ratio between volumes of 93 octane to 94 octane gasolines purchased by owners of 1971 through 1974 model automobiles (three-grade schedules only).*

2) *The assumption regarding the octane level of the special third grade of gasoline (low lead or clear, low octane fuel).*

3) *The forecast of miles driven for future years and hence the volumes of gasoline required in both the reference schedules and the subject schedules.*

The results of these analyses are presented in Table 29.

In general, these results are consistent with other studies of lead removal. They show the added cost of gasoline to be sensitive to changes in clear pool octane requirements. The increased sensitivity to assumptions affecting clear pool octane number of Schedule L, as compared to Schedule A, is a consequence of the fact that a given improvement in octane quality is more expensive at high octane levels than at low octane levels.

The year 1976 was selected as a key year for this analysis because many of the effects considered most important to the study were present in this year. These effects include:

1) The 1976 clear pool octane numbers tended to be a maximum.

2) The 1975 and 1976 model cars accounted for a fair share of the market but did not dominate it as in later years.

Consequently, it was judged that this year would represent a turning point in the sensitivity of the study to these assumptions.

TABLE 29

EFFECT ON ADDED COST AND INVESTMENT RESULTS OF VARYING KEY ASSUMPTIONS

(Year = 1976)

Assumption Change		Schedule A	Schedule L	Schedule G	Schedule M
(1) 1971 - 1974 models buy in 25/75 ratio of 93/94 octane gasolines.	Added Cost, ¢/gal	- .05	.02	*	*
	Investment, MM Dollars	-233.	37.		
(2) 1971 - 1974 models buy in 75/25 ratio of 93/94 octane gasolines.	Added Cost, ¢/gal	.06	- .02	*	*
	Investment, MM Dollars	276.	- 37.		
(3) Third grade is 91.0 octane.	Added Cost, ¢/gal	- .13	- .20	*	*
	Investment, MM Dollars	-236.	-550.		
(4) Gasoline volumes up 10%.	Added Cost, ¢/gal	.00	.00	.01	.00
	†Investment, MM Dollars	81.	247.	113.	315.

*Does not apply.

†In addition to $926 million needed to raise volume in reference case.

4.7.1 Assumption Involving Ratio Between Grades

Varying the relative amounts of the 93 and 94 octane gasolines purchased by owners of 1971 - 1974 model automobiles produced results consistent with this change in clear pool octane. In Schedule A, an increase in the relative amount of 93 octane caused an increase in cost because the 93 octane has a higher clear octane rating than the 94 octane gasoline. Schedule L shows the opposite effect because both grades are clear.

The sensitivity of the added costs to this would be somewhat less for all schedules in the earlier years, peaking at about 1975, and then declining again as the 1971 - 1974 models disappear from the road in subsequent years. Schedule L shows a greater sensitivity to this assumption because the clear octane level of the total gasoline pool is higher.

4.7.2 Assumption Involving Octane of Third Grade

Added costs vary with this assumption in a manner consistent with clear pool octane changes and level. The difference between the Schedule A effect, -.13¢/gal, and the Schedule L effect, -.20¢/gal, reflects the fact that, at the higher clear pool octane level represented by Schedule L, the cost of improving octane a small amount is about 50% higher than it is at the Schedule A clear octane levels.

The magnitude of this effect will vary with the amount of the third grade of gasoline being sold. Thus it will increase with time in Schedule A. The sensitivity of Schedule L to this effect should remain relatively constant since the effect of increasing the volume of the third grade is offset to a great extent by the consequent lowering of the total pool clear octane.

In this analysis no further loss in automotive engine efficiency is assumed by lowering octane. If such a loss in efficiency did occur it still should not have a significant influence on these per gallon added cost differences. A consumer effect would be noticed if more gasoline were required at 91 RON.

4.7.3 Assumption Involving Total Gasoline Volume

The added cost for deleading gasoline when expressed on a cents/gallon basis is not sensitive to this assumption. This implies that the investments and operating costs change in direct proportion to volume within the range studied. It must be pointed out that the limitation to construction was not a factor in these studies. A higher gasoline demand will delay the date at which all gasolines can be manufactured clear.

4.7.4 Adjustment of Added Cost for Variations in Gasoline Grade Volumes and Prices

Added production costs for unleaded gasoline are based upon a fixed average gasoline price at the refinery.

The cents/gallon effect shown in Table 30 can be interpreted as the across-the-board price increase (above the stated grade prices) to maintain the per-gallon price for total gasoline equal to the reference case. Alternatively, had the added costs been calculated on the basis of the indicated grade prices, the cents/gallon added costs would have been higher by the amount shown.

The relative amount of premium gasoline in the subject schedules is considerably lower than in the reference schedule. Therefore, if the prices for the individual grades of gasoline had been held fixed, the average price for gasoline would have been declining in the subject schedules.

TABLE 30

EFFECT OF GRADE MIX VARIATIONS ON AVERAGE GASOLINE REFINERY NETBACKS**

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
2-Grade Schedules										
% 94 RON	67.54	72.75	77.38	81.17	84.87	88.00	90.87	93.27	95.24	96.81
% 100 RON	32.46	27.25	22.62	18.83	15.13	12.00	9.13	6.73	4.76	3.19
¢/Gal Netback	11.83	11.70	11.58	11.49	11.40	11.32	11.25	11.19	11.14	11.10
Effect, ¢/Gal*	0.15	0.28	0.40	0.49	0.58	0.66	0.73	0.79	0.84	0.88
3-Grade Schedules										
% 93 RON	6.75	12.47	17.58	21.85	32.96	42.44	50.73	57.69	63.63	68.85
% 94 RON	60.79	60.28	59.80	59.32	51.91	45.56	40.14	35.58	31.61	27.96
% 100 RON	32.46	27.25	22.62	18.83	15.13	12.00	9.13	6.73	4.76	3.19
¢/Gal Netback	11.83	11.70	11.58	11.48	11.39	11.31	11.24	11.18	11.13	11.09
Effect, ¢/Gal*	0.15	0.28	0.40	0.50	0.59	0.67	0.74	0.80	0.85	0.89

*Added cost of gasoline associated with a schedule would be increased by this amount if the refinery netback for each grade of gasoline had been fixed.

**Based on the following netbacks:

93 RON	11.0000 ¢/gal
94 RON	11.0238 ¢/gal
100 RON	13.5000 ¢/gal

4.8 EFFECTS ON SMALL REFINERS

Earlier studies of unleaded gasoline economics have shown that the economic impact of changing gasoline formulations falls more heavily upon small refiners than upon large ones. This is due, almost exclusively, to the effects of economies of scale, which result in refinery processes being more costly per unit of throughput when built in small sizes than when built in large sizes. In this section the discussion of the small refining industry is broken into four topics. The first is a history of the role of small refiners in the total U.S. refining industry to give a perspective of the importance of this industry segment and of its likely future. Second, the small refinery economic effects of lead reduction are discussed. Third, present programs of economic assistance to small refineries are discussed, and fourth, alternate futures of the small refiner are examined.

In this study, small refiners have been defined as those processing less than 35,000 barrels per day of crude oil. The cost penalties of small size are not confined solely to refineries of this size. Earlier work, however, has shown that small refineries, by this definition, experience a particularly sharp increase in added costs when being extended to produce unleaded gasoline. Furthermore, this 35,000 barrel per day size represents an approximate breakpoint below which certain high-cost processes such as hydrocracking, which is economical for unleaded gasoline manufacture in larger refineries, can no longer be justified because of size and economies of scale. In this study all refineries classified as non-small refineries, those larger than 35,000 barrels per day, represent an average size equivalent to about 100,000 barrels a day of crude capacity. Many industry people use a "rule of thumb" that, in the long run, grass roots refineries built in the United States can be economical only if they are at least 100,000 barrels per day in capacity.

Small refineries tend to fall into two categories: those that are producing gasoline and other fuels for the general energy market, and those that are producing specialty products, for example, asphalt for road building. There are a larger number of these asphalt refineries, and they produce certain by-products that enter the general fuels market. Their economic viability, however, depends on the asphalt market and, as such, they are of little interest in our present studies and specifically have been excluded from those data that are used to discuss the effects on small refineries. The remaining small refineries, those that are principally in the fuel products business, have historically existed for one reason. That is, they were close enough to a supply of crude oil that transportation cost savings made it practical to build a small refinery, operating on local crude oil to supply a local market. Tables 31 and 32 show statistical histories of the small refiner for the 20-year period 1950 through 1970. During this time, the number of small refineries declined from 155 to 74. This reduction came about by shutting down 75 refineries, expanding 45 refineries beyond 35,000 barrels a day crude capacity and building 39 new small refineries. In

TABLE 31

GROWTH AND DECLINE TRENDS AMONG SMALL U.S. GASOLINE REFINERS FROM 1950 THROUGH 1970

PERIOD	NO. OF SMALL REFINERIES (BEGINNING)	NUMBER SHUT DOWN	NUMBER EXPANDED TO 35,000+	NEW SMALL REFINERIES ADDED
1950 - 1960	155	47	28	22
1960 - 1970	102	28	17	17
1970 -	74	?	?	?

TABLE 32

CRUDE CAPACITY TRENDS OF SMALL REFINERIES

	1950			1960			1970		
	SMALL FUEL REFINERIES	SMALL SPECIALTY REFINERIES	ALL REFINERIES	SMALL FUEL REFINERIES	SMALL SPECIALTY REFINERIES	ALL REFINERIES	SMALL FUEL REFINERIES	SMALL SPECIALTY REFINERIES	ALL REFINERIES
CRUDE RUNS	1,683,550	506,815	6,540,265	1,542,120	420,370	9,699,955	1,244,586	429,991	12,681,387
	25.7	7.7	100	15.9	4.3	100	9.8	3.4	100

this same 20-year period, the percent of crude charged to the small refinery sector decreased from 26% in 1950 to 10% in 1970. From Tables 31 and 32 it can also be seen that, although the number of small refineries decreased by almost 50%, the selective process of shutting down the smallest plants first caused their total crude runs to decrease only about 25%. Nevertheless, during this period their portion of the total U.S. refining business declined over 60% from 25.7% to 9.8%.

One significant reason for the decline of the small refiner can be traced to the quality of gasoline which is sold today as compared with gasoline sold in 1950. In 1950 the average Research Octane Number of gasoline was about 85, and in 1970 the average was about 96.5. Producing higher octane gasoline, as has been discussed earlier, requires more complex refinery processes and requires ones which are more capital intensive. Effects of size have thus become more pronounced as the investment per barrel of crude throughput has risen to meet increasing gasoline quality requirements.

Previous Bonner & Moore studies of the economics of manufacturing unleaded motor gasoline have used as many as twelve models. The models represented major geographic areas within the U.S. and various sized refineries within these areas. This work has provided experience in extrapolating economic behavior of several models to national behavior. Subsequent work done with smaller sets of models has shown the earlier work to be an excellent guide for this extrapolation.

As noted in other areas of this report, the added cost of gasoline manufacture stems from five cost contributors:

1) *Costs associated with investments.*

2) *Variable operating costs.*

3) *Lead reduction credits.*

4) *By-product credits (debits).*

5) *Raw stock costs.*

Costs associated with investments usually account for the major portion of added costs, and become magnified for the smaller refiner. Figure 4-1 shows the investment required to manufacture unleaded motor gasoline versus refinery size, expressed in volume of motor gasoline manufactured. This plot represents data from six refinery sizes within the mid-continent[3]. Three additional points are shown from a more recent study. Based upon this earlier work, the assumption was made that the slope of this effect stays constant although the investment required may be less for lower octane requirements. Therefore, if the added capital investment required for a given refinery is known, the similar added capital needs for other sized refineries can be derived.

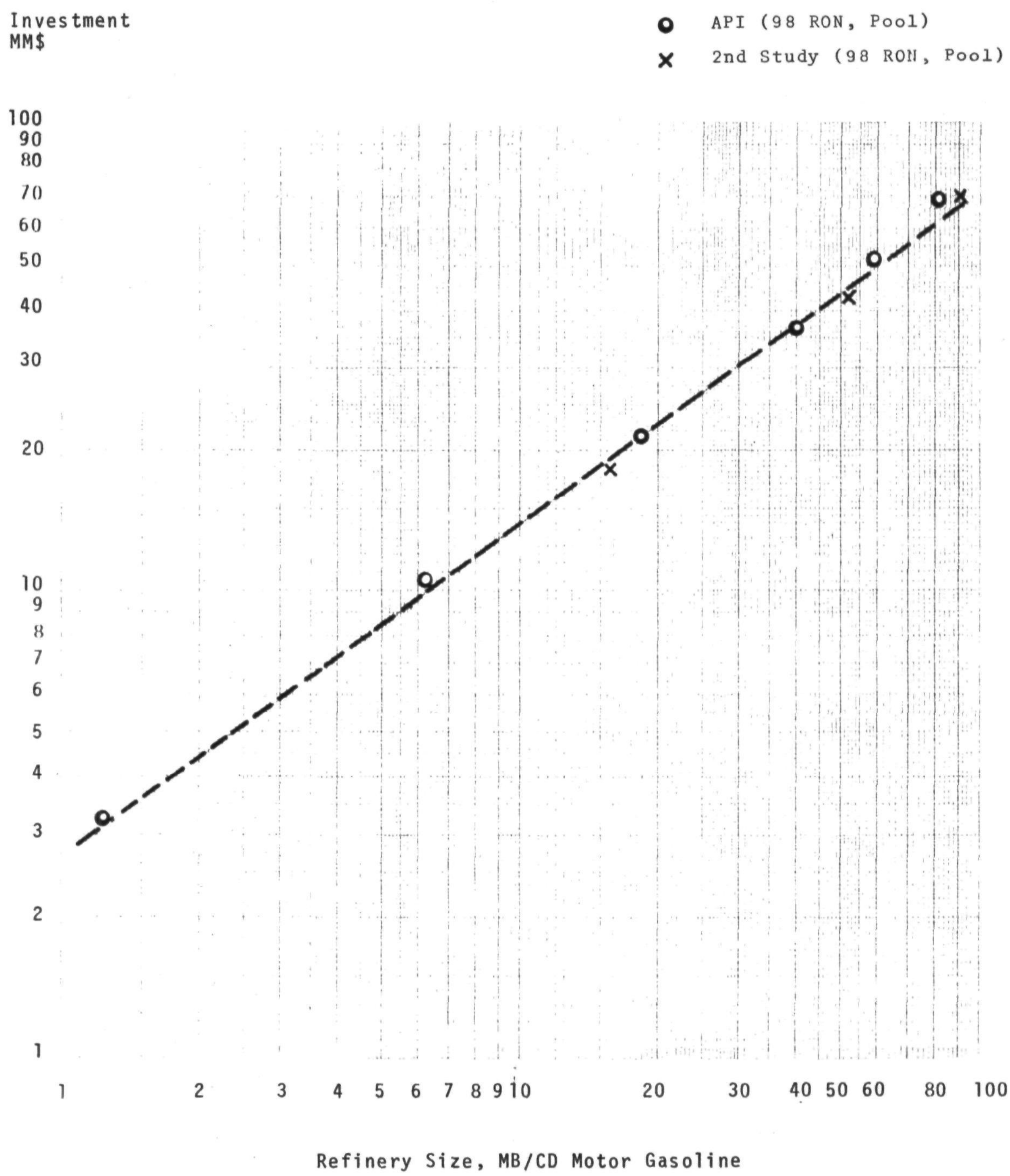


Figure 4-1. Refinery Size versus Added Capital Investment to *Manufacture Unleaded Motor Gasoline*

Variable operating costs and lead reduction credits appear to be essentially linear with refinery size. By-product costs and raw stock costs are somewhat greater (per barrel of gasoline) for small plants but not significantly so until throughput falls well below the 35,000 barrel/day cutoff. Figure 4-2 illustrates the lower efficiency of gasoline production for small refineries as reflected by added crude requirements. At this small throughput, the refineries represented account for a negligible part of the nation's gasoline production. Even so, the extrapolation procedures used to obtain national behavior predictions conservatively assume uniform gasoline yield (regardless of size).

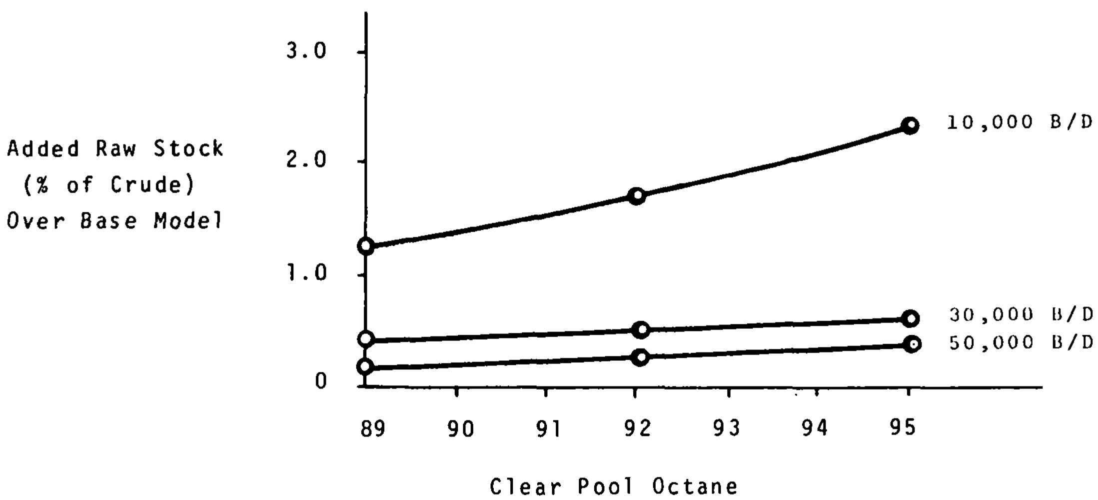


Figure 4-2. Added Raw Stock versus Pool Octane for Varying Refinery Sizes

To further illustrate how refinery size affects added costs for producing unleaded gasoline, the factors described above have been used to estimate added costs for the lead removal schedules A, G, L, and M studied in this report. Table 33 gives an example of these estimates. It must be understood that these small refinery costs have not been derived in the detailed manner that has been used for obtaining the principal results. Instead these principal results have been used as a base to which the estimation procedure has been applied.

TABLE 33

EXTRAPOLATION OF REFINERY SIZE EFFECTS

ON COST ESTIMATES FOR SCHEDULE A

Added Cost for Small Refineries, ¢/Gal Based on Total Gasoline	1971	1976	1980
100 MBCD Crude	0.16	0.21	0.21
50 MBCD Crude	0.19	0.24	0.24
30 MBCD Crude	0.20	0.26	0.26
10 MBCD Crude	0.25	0.33	0.33

It must be recognized that the "average" cost presented in this report is greater than that incurred by the larger refinery and smaller than that incurred by the small one. Any program which attempts to compensate costs (via assistance programs, taxation or allotments, etc.) adds its burden to the incurred cost and must be borne by some agent (taxpayer, industry or consumer). Assessment of this kind of cost is beyond the scope of this study.

The small refiner has been assisted directly or indirectly by the Federal Government for many years. The principal assistance program has been an indirect one. This has been the crude oil import program initiated in 1959 with its sliding scale for permissible import quotas. This program was not conceived as a direct small refinery assistance program. Its provisions, however, guarantee the small refiner access to any benefits of low cost crude imports to a degree not allowed large refineries. Historically, a license or "ticket" to import foreign crude has been valued at $0.90 to $1.25 per barrel. Higher values (as well as lower values) have been occasionally realized on a spot basis. These values reflect sales price differences between domestic and foreign crude, less transportation cost differences. In the latter half of 1970, and for several months of 1971, tanker shortages have driven transportation costs up so sharply that import "tickets" have virtually no value. Future tanker shortages as well as an approach to parity between foreign and domestic crude prices each serve to reduce the value of this indirect small refiner assistance program. Table 34 summarizes the import allocation method as it existed until the end of 1970. A small refiner with an import quota equivalent to 15% of his crude throughput has been able to realize an income of roughly $0.15 per barrel of throughput from sale of this oil import allocation. Compared to a large refinery with an import quota of perhaps 4% of throughput, this small refinery is subsidized by $0.11 per barrel of crude. If this is allocated to gasoline production, it becomes about $0.21 per barrel or

0.5¢ per gallon. It must be remembered that small refinery added costs for unleaded gasoline, shown earlier, are additive to the present cost differences partially represented by these assistance programs.

TABLE 34

CRUDE OIL IMPORT ALLOCATION FORMULA

Refinery Average Daily Throughput	Allocation As Percent of Throughput
PAD Districts I-IV (1970)	
0 - 10,000	19.5
10 - 30,000	11.0
30 - 100,000	7.0
Over - 100,000	3.0
PAD District V (1970)	
0 - 10,000	40.0
10 - 30,000	9.3
30 - 100,000	4.3
Over - 100,000	1.9

Another type of assistance program is the small business petroleum product purchasing procedure. In general this method guarantees that some portion of government purchases (up to 45%) will be made from small refineries at prices that in part reflect their manufacturing cost disadvantage. In one type of preferential purchase called a "total set-aside", the small refiner is able to bid competitively against other small refiners without competing against larger suppliers if he bids a fair market price. In the other type of purchase called a "partial set-aside", a small refiner bidder may supply product preferentially over a large refiner if he meets the large refiner's price.

Financial data on small refineries are not generally available. Most of the refineries are closely or privately held. Therefore, they do not come under S.E.C. disclosure requirements, and it is necessary to speculate on the profitability of this part of the industry. It is probably realistic to say that the profit margin for small refiners has been less than their income from the sale of import tickets. Under this condition then, it is apparent that the basic refining of crude oil in a small refinery has been unprofitable in the United States for many years. In 1958 the small refinery industry had reached a virtual crisis in profitability and was unable to generate either cash flows or borrowing power to modernize and expand facilities. The implementation of the oil import program bred considerable new economic life into this part of the industry and has prolonged it well beyond what would probably have occurred under conditions which existed in 1958. Had the import program not been enacted, it is reasonable to assume that the small refinery industry would have continued until its equipment was no longer operable. It would not have been able to generate funds to cover depreciation and, therefore, would have been unable to replace equipment with new modern facilities.

In the intervening years since 1958, however, the small refinery industry has been able to sustain itself and, by and large, show modest profits for the owners. Today there are many small refiners which have modern plants able to produce high quality products.

The fundamental economics of small refiners are harmed by two long-term trends. One has been cited earlier, namely the continued increase in gasoline octane necessitating more expensive refining equipment. A second factor has been the continuous building of pipelines for both crude oil and refined products. Pipeline transportation is sufficiently low in cost that the old economics of building a small refinery at a local crude source to avoid costly rail or truck transportation is no longer widely applicable. This trend could well be reversed, however, if a chronic energy shortage develops which results in prices for basic fuel products, such as heating oils and distillates, that will permit a reasonable return on investment to be realized by a refinery company without its own crude production. Thus, the small refinery industry might find a new opportunity to supply small local markets with non-gasoline fuels that can be produced in relatively simple plants.

Another, and perhaps more likely, avenue for rationalizing the small refinery industry under the economic conditions of the '70's would be through merger or pooled operation of large modern plants. From a logistics standpoint, this option is open to about 1/2 to 2/3 of the small gasoline refiners. The small refinery "belt" in the U.S. extends from the Mississippi Delta to the Montana-Idaho border and is approximately 300 miles wide. In this band lie 47% of all the U.S. small refiners. In addition, there are other localized groupings of refiners which in the aggregate represent another 27% of U.S. small refiners. These localized groupings are in California, in Michigan, in the region of Northern Kentucky, Indiana, Western West Virginia, and in Western Pennsylvania. It appears, considering logistics alone, that combining almost 75% of present U.S. small refineries into economic size units is possible.

Any program of rationalization through mergers or acquisitions would require major amounts of capital. These amounts are beyond the ability of most small refiners to acquire either through debt or equity sources. Any program to encourage rationalization of this industry must address this problem of undercapitalization.

4.9 IMPACT ON THE CONSTRUCTION INDUSTRY

The impact of Schedules A, G, L, and M on the construction industry was studied on a national basis by taking the investments required in the individual refinery models and scaling these to a national level. The methods used to carry out this scaling and to make adjustments for obsolescence and replacements are described in paragraph 5.4.

Table 35 shows the investments being completed by the construction industry in each year of Schedules A, G, L and M, and the reference schedule. That is, the facilities represented by these investments are operable for the first time in the year for which the investment is recorded.

It should be noted that all investments shown in these tables other than U.S. and Canadian refining are constant for all schedules. Also, U.S. refining investments for the years 1970, 1971, and 1972 are constant for all schedules. The refinery investments for these years were based on data reported in the Oil and Gas Journal and reported levels of engineering and construction backlog.

Figures 4-3, 4-4, 4-5, and 4-6 plot these refinery investments together with the forecast maximum construction industry capacity available to refining. The sharp peak construction requirement in 1974 for Schedule G is readily apparent in Figure 4-4. This overshoot cannot be compensated for any earlier than 1976.

Table 36 gives a breakdown of the construction dollar according to the various sectors of the construction industry for each schedule. This breakdown includes a distribution of the total investment dollars backward in time to reflect the fact that engineering must start well ahead of materials ordering, etc. For convenience in observing the effect of the various schedules so far as producing boom or bust conditions is concerned, the lower half of these tables describes the changes in construction activity from year to year.

TABLE 35

CONSTRUCTION INDUSTRY INVESTMENTS

(Installed Capacity for Years Listed)

[illegible]

INVESTMENT SUMMARY - MM$/YEAR

	PETROCHEMICAL			REFINING				TOTAL		
	FOREIGN	US/CANADA	TOTAL	FOREIGN	CANADA	US	TOTAL	FOREIGN	US/CANADA	TOTAL
1970	[illegible]	1,200	1,300	105	115	1,050	1,270	205	2,365	2,570
1971	[illegible]	1,330	1,440	125	127	1,158	1,411	235	2,616	2,851
1972	[illegible]	1,500	1,620	140	70	635	845	260	2,205	2,465
1973	[illegible]	1,680	1,815	150	101	918	1,169	285	2,699	2,984
1974	[illegible]	1,880	2,030	160	125	1,138	1,424	310	3,144	3,454
1975	[illegible]	2,020	2,185	170	115	1,046	1,331	335	3,181	3,516
1976	[illegible]	2,220	2,405	180	117	1,060	1,356	365	3,396	3,761
1977	[illegible]	[illegible]	2,645	185	136	1,235	1,555	390	3,810	4,200
1978	[illegible]	2,690	2,920	190	123	1,120	1,434	420	3,934	4,354
1979	[illegible]	2,960	3,210	195	131	1,189	1,515	445	4,280	4,725
1980	[illegible]	3,250	3,530	200	132	1,199	1,531	480	4,581	5,061
1981	[illegible]	3,580	3,890	205	133	1,208	1,546	515	4,921	5,436
1982	345	3,930	4,275	210	134	1,223	1,567	555	5,287	5,842
TOTALS	[illegible]	30,680	33,265	2,215	1,560	14,179	17,953	4,800	46,418	51,218

SCHEDULE G

INVESTMENT SUMMARY - MM$/YEAR

	PETROCHEMICAL			REFINING				TOTAL		
	FOREIGN	US/CANADA	TOTAL	FOREIGN	CANADA	US	TOTAL	FOREIGN	US/CANADA	TOTAL
1970	100	1,200	1,300	105	115	1,050	1,270	205	2,365	2,570
1971	110	1,330	1,440	125	127	1,158	1,411	235	2,616	2,851
1972	120	1,500	1,620	140	70	635	845	260	2,205	2,465
1973	135	1,680	1,815	150	119	1,085	1,354	285	2,884	3,169
1974	150	1,880	2,030	160	383	3,482	4,025	310	5,745	6,055
1975	165	2,020	2,185	170	142	1,292	1,605	335	3,455	3,790
1976	185	2,220	2,405	180	140	1,269	1,589	365	3,629	3,994
1977	205	2,440	2,645	185	122	1,112	1,419	390	3,674	4,064
1978	230	2,690	2,920	190	138	1,253	1,581	420	4,081	4,501
1979	250	2,960	3,210	195	131	1,193	1,519	445	4,284	4,729
1980	280	3,250	3,530	200	128	1,165	1,493	480	4,543	5,023
1981	310	3,580	3,890	205	130	1,180	1,515	515	4,890	5,405
1982	345	3,930	4,275	210	131	1,193	1,535	555	5,255	5,810
TOTALS	2,585	30,680	33,265	2,215	1,877	17,068	21,160	4,800	49,625	54,425

TABLE 35 (cont.)

[illegible] L

IN[illegible] $/YEAR

	[illegible]			REFINING				TOTAL		
	[illegible]	[illegible]	TOTAL	FOREIGN	CANADA	US	TOTAL	FOREIGN	US/CANADA	TOTAL
[illegible]	[illegible]	[illegible]	[illegible]	105	115	1,050	1,270	205	2,365	2,570
[illegible]	[illegible]	[illegible]	[illegible]	125	127	1,158	1,411	235	2,616	2,851
[illegible]	[illegible]	[illegible]	[illegible]	140	70	635	845	260	2,205	2,465
[illegible]	[illegible]	[illegible]	[illegible]	150	152	1,386	1,688	285	3,218	3,503
[illegible]	[illegible]	[illegible]	[illegible]	160	178	1,615	1,953	310	3,673	3,983
[illegible]	[illegible]	[illegible]	[illegible]	170	236	2,147	2,553	335	4,403	4,738
[illegible]	[illegible]	[illegible]	[illegible]	180	233	2,116	2,529	365	4,569	4,934
1977	[illegible]	2,440	[illegible]	185	112	1,019	1,316	390	3,571	3,961
[illegible]	[illegible]	[illegible]	[illegible]	190	113	1,030	1,333	420	3,833	4,253
[illegible]	[illegible]	[illegible]	[illegible]	195	114	1,032	1,341	445	4,106	4,551
[illegible]	[illegible]	[illegible]	[illegible]	200	120	1,093	1,413	480	4,463	4,943
[illegible]	[illegible]	[illegible]	[illegible]	205	119	1,085	1,409	515	4,784	5,299
[illegible]	[illegible]	[illegible]	4,275	210	121	1,096	1,427	555	5,147	5,702
TOTALS	[illegible]	[illegible]	[illegible]	2,215	1,811	16,461	20,487	4,800	48,952	53,752

SCHEDULE [illegible]

INVEST[illegible] $/YEAR

	[illegible]TROCHEMICAL			REFINING				TOTAL		
	[illegible]	US/CANADA	TOTAL	FOREIGN	CANADA	US	TOTAL	FOREIGN	US/CANADA	TOTAL
[illegible]	[illegible]	[illegible]	[illegible]	105	115	1,050	1,270	205	2,365	2,570
[illegible]	[illegible]	[illegible]	[illegible]	125	127	1,158	1,411	235	2,616	2,851
[illegible]	[illegible]	[illegible]	[illegible]	140	70	635	845	260	2,205	2,465
[illegible]	[illegible]	[illegible]	[illegible]	150	152	1,386	1,688	285	3,218	3,503
[illegible]	[illegible]	[illegible]	[illegible]	160	178	1,615	1,953	310	3,673	3,983
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	236	2,147	2,553	335	4,403	4,738
[illegible]	[illegible]	[illegible]	[illegible]	180	265	2,413	2,858	365	4,898	5,263
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	126	1,145	1,456	390	3,711	4,101
[illegible]	[illegible]	[illegible]	[illegible]	190	126	1,144	1,460	420	3,960	4,380
[illegible]	[illegible]	[illegible]	[illegible]	195	124	1,127	1,446	445	4,211	4,656
[illegible]	[illegible]	[illegible]	[illegible]	200	126	1,146	1,472	480	4,522	5,002
[illegible]	[illegible]	[illegible]	[illegible]	205	127	1,152	1,484	515	4,859	5,374
[illegible]	[illegible]	[illegible]	[illegible]	210	128	1,165	1,503	555	5,223	5,778
TOTALS	[illegible]	[illegible]	[illegible]	2,215	1,901	17,283	21,399	4,800	49,864	54,664

TABLE 35 (cont.)

REFERENCE SCHEDULE

INVESTMENT [illegible] $/YEAR

	PETROCHEMICAL			REFINING				TOTAL		
	FOREIGN	US/CANADA	TOTAL	FOREIGN	CANADA	US	TOTAL	FOREIGN	US/CANADA	TOTAL
1970	[illegible]	[illegible]	[illegible]	105	115	1,050	1,270	205	2,365	2,570
1971	[illegible]	[illegible]	[illegible]	125	127	1,158	1,411	235	2,616	2,851
1972	[illegible]	[illegible]	1,620	140	70	635	845	260	2,205	2,465
1973	[illegible]	[illegible]	[illegible]	150	94	854	1,098	285	2,628	2,913
1974	[illegible]	[illegible]	[illegible]	160	96	869	1,125	310	2,845	3,155
1975	[illegible]	[illegible]	[illegible]	170	97	879	1,146	335	2,996	3,331
1976	[illegible]	[illegible]	[illegible]	180	90	820	1,091	365	3,131	3,496
1977	[illegible]	[illegible]	[illegible]	185	90	817	1,092	390	3,347	3,737
1978	[illegible]	[illegible]	[illegible]	190	93	846	1,129	420	3,629	4,049
1979	[illegible]	[illegible]	[illegible]	195	90	819	1,104	445	3,869	4,314
1980	[illegible]	[illegible]	[illegible]	200	95	865	1,160	480	4,210	4,690
1981	[illegible]	[illegible]	[illegible]	205	92	838	1,135	515	4,510	5,025
1982	[illegible]	[illegible]	4,275	210	97	879	1,186	555	4,906	5,461
TOTALS	[illegible]	[illegible]	[illegible]	2,215	1,246	11,330	14,791	4,800	43,256	48,056

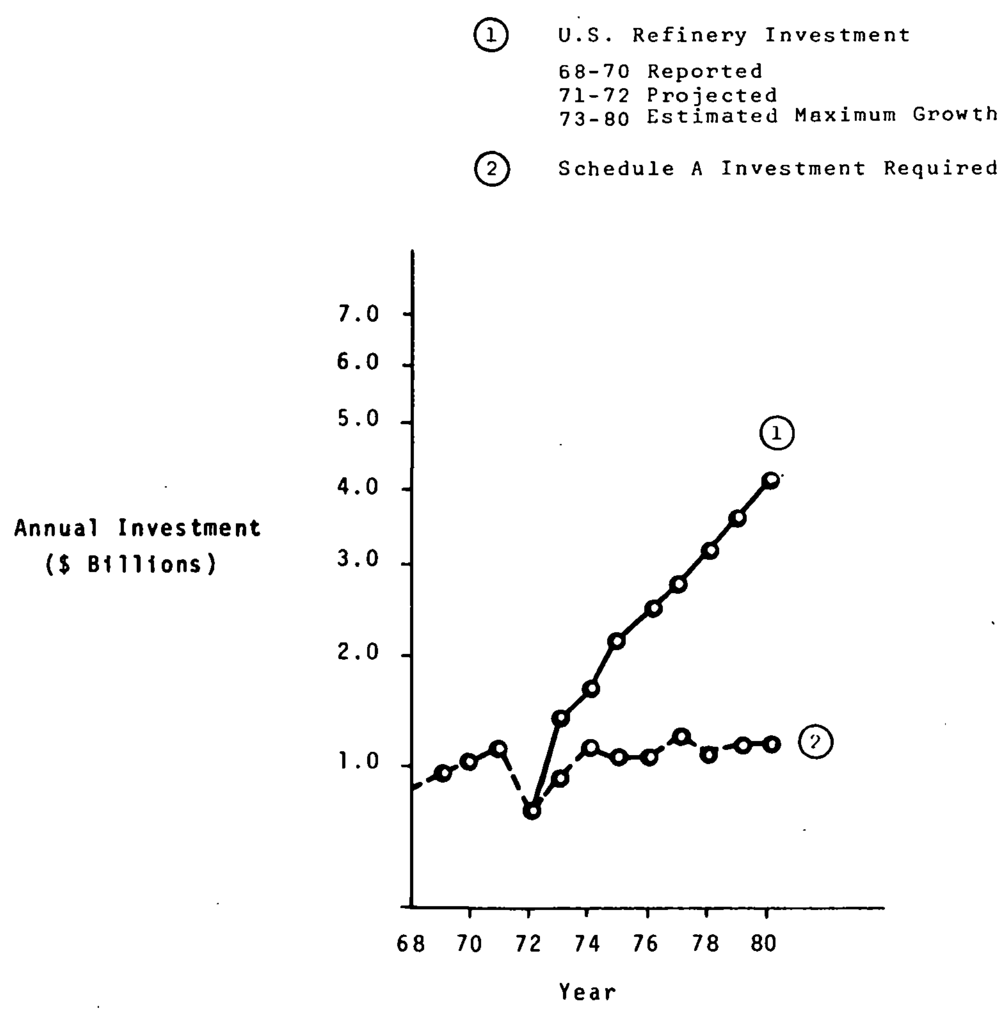


Figure 4-3. Annual Investment ($ Billions)
For Schedule A

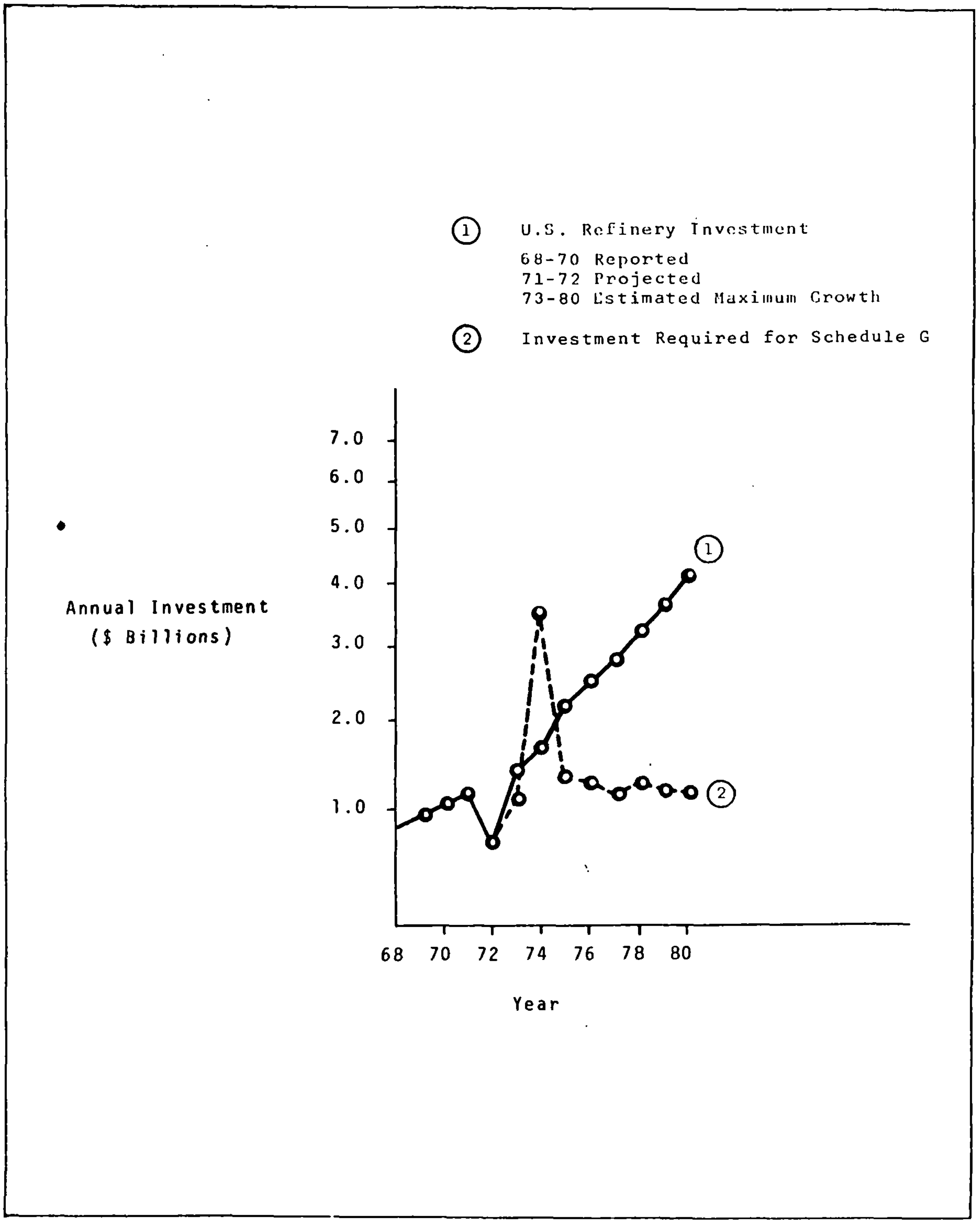


Figure 4-4. Annual Investment ($ Billions) For Schedule G

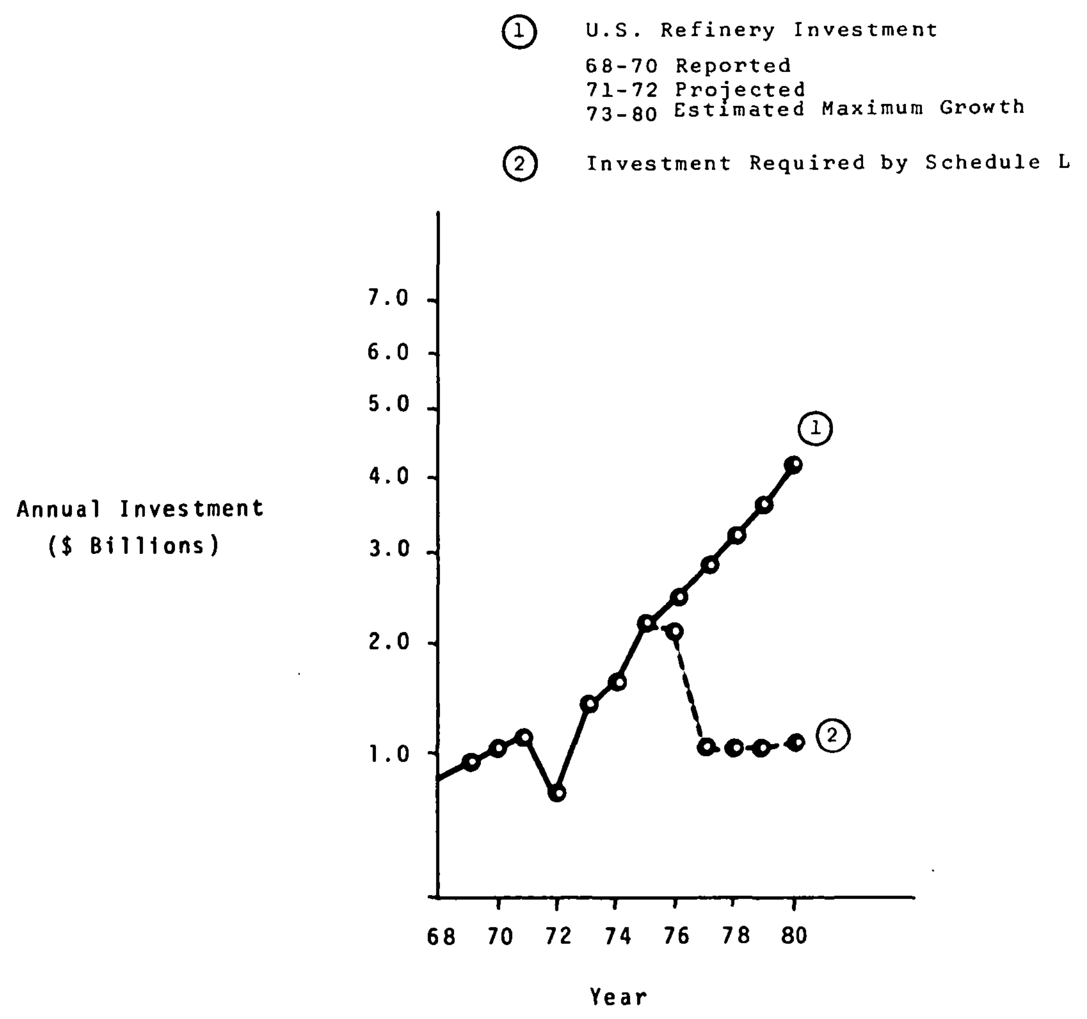


Figure 4-5. Annual Investment ($ Billions) For Schedule L

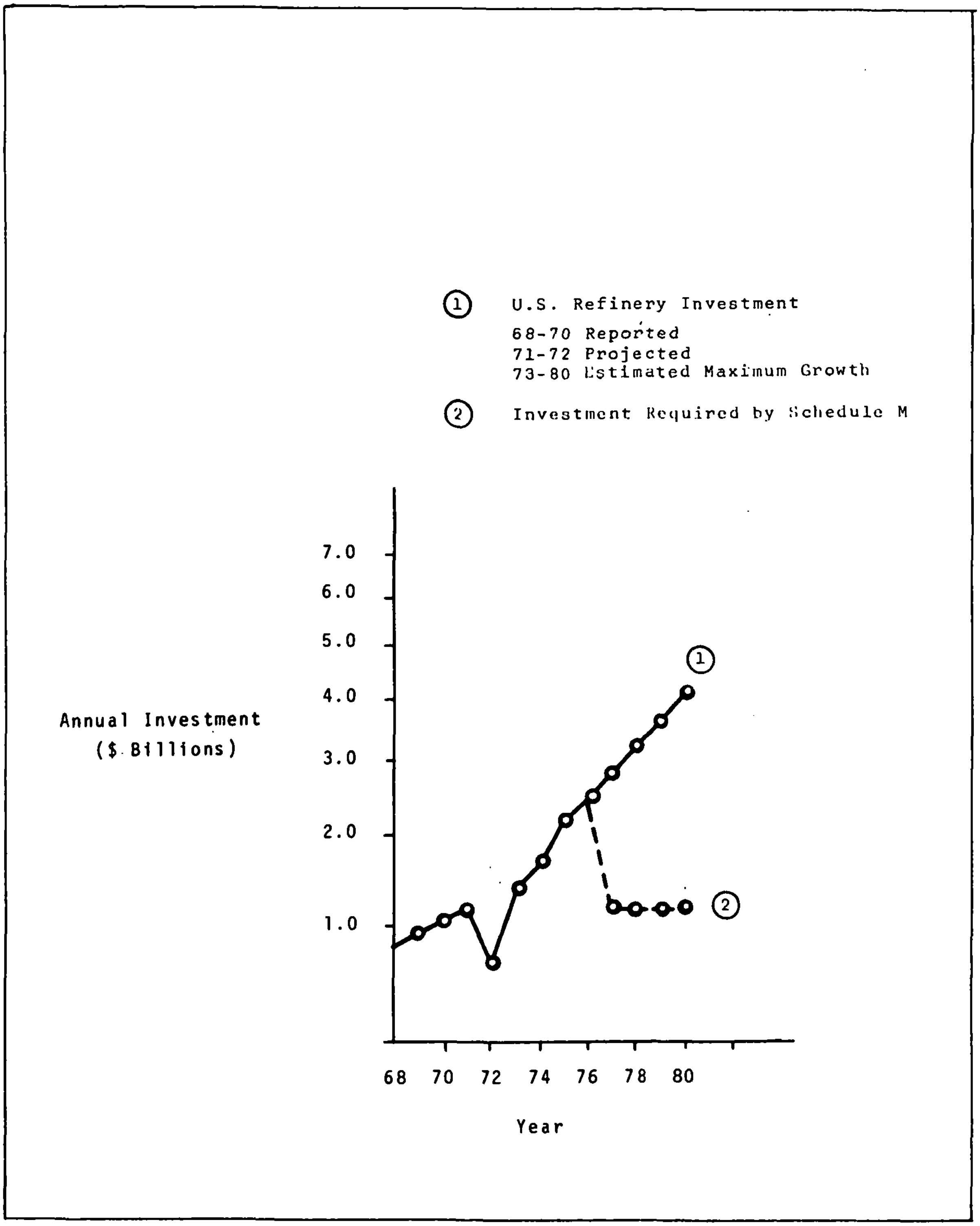


Figure 4-6. Annual Investment ($ Billions) For Schedule M

TABLE 36

CONSTRUCTION COSTS BY SECTOR

SCHEDULE A

TOTAL US & FOREIGN - MM$/YR

	ENGINEERING	MATERIALS	FIELD LABOR	FEES & MISC	
1971	352	1,217	478	437	2,484
1972	412	1,449	527	502	2,890
1973	450	1,606	619	571	3,246
1974	471	1,661	651	596	3,379
1975	513	1,804	686	638	3,641
1976	553	1,962	758	700	3,973
1977	586	2,067	801	738	4,193
1978	632	2,233	859	795	4,519
1979	678	2,394	924	853	4,848
1980	728	2,572	991	916	5,207
TOTALS	5,374	18,966	7,294	6,746	38,380

NET CHANGE AS PERCENT OF PRIOR YEAR

1971	1	-3	-8	-6	-4
1972	17	19	10	15	16
1973	9	11	17	14	12
1974	5	3	5	4	4
1975	9	9	5	7	8
1976	8	9	11	10	9
1977	6	5	6	5	6
1978	8	8	7	8	8
1979	7	7	7	7	7
1980	7	7	7	7	7

SCHEDULE L

TOTAL US & FOREIGN - MM$/YR

	ENGINEERING	MATERIALS	FIELD LABOR	FEES & MISC	
1971	382	1,306	479	451	2,617
1972	477	1,706	602	578	3,363
1973	558	1,588	726	680	3,952
1974	623	2,257	856	786	4,523
1975	585	2,150	920	800	4,456
1976	537	1,880	790	697	3,903
1977	568	2,003	773	716	4,060
1978	612	2,156	828	768	4,366
1979	661	2,332	897	831	4,720
1980	710	2,503	965	893	5,071
TOTALS	5,714	20,281	7,836	7,200	41,031

NET CHANGE AS PERCENT OF PRIOR YEAR

1971	10	4	-8	-2	1
1972	25	31	26†	28	28
1973	17	17	21	18	18
1974	12	14	18	16	14
1975	-6	-5	7	2	-1
1976	-8	-13	-14	-13	-12
1977	6	7	-2	3	4
1978	8	9	7	7	8
1979	8	8	8	8	8
1980	7	7	8	7	7

†Because of the depressed prior year, this percentage could be achieved even though it is slightly above the maximum growth rate allowed in that year. (See page 5-39.)

SCHEDULE G

TOTAL US & FOREIGN - MM$/YR

	ENGINEERING	MATERIALS	FIELD LABOR	FEES & MISC	
1971	363	1,249	478	442	2,532
1972	573	1,951	558	595	3,678
1973	643	2,486	999	893	5,021
1974	516	1,814	836	697	3,863
1975	522	1,858	734	669	3,782
1976	553	1,946	752	693	3,944
1977	596	2,114	814	753	4,277
1978	630	2,230	868	798	4,526
1979	673	2,377	918	848	4,816
1980	724	2,556	985	910	5,175
TOTALS	5,793	20,581	7,943	7,297	41,614

NET CHANGE AS PERCENT OF PRIOR YEAR

1971	5	-1	-8	-4	-2
1972	58	56	17	35	45
1973	12	27	79	50	37
1974	-20	-27	-16	-22	-23
1975	1	2	-12	-4	-2
1976	6	5	2	4	4
1977	8	9	8	9	8
1978	6	5	7	6	6
1979	7	7	6	6	6
1980	7	8	7	7	7

SCHEDULE [illegible]

TOTAL US & FOREIGN - MM$/YR

	ENGINEERING	MATERIALS	FIELD LABOR	FEES & MISC	
[illegible]	342	1,306	479	451	2,617
[illegible]	477	1,706	602	578	3,363
[illegible]	558	1,988	726	680	3,952
[illegible]	642	2,313	857	795	4,607
[illegible]	615	2,279	967	843	4,705
[illegible]	555	1,960	828	725	4,058
1977	584	2,063	799	737	4,183
[illegible]	624	2,202	851	785	4,461
[illegible]	670	2,364	911	843	4,788
[illegible]	720	2,541	979	905	5,145
[illegible]	[illegible]	20,711	7,999	7,343	41,880

NET CHANGE AS PERCENT OF PRIOR YEAR

[illegible]	10	4	-8	-2	1
[illegible]	25	31	26†	28	28
[illegible]	17	17	21	18	18
[illegible]	15	16	18	17	17
[illegible]	-4	-1	13	6	2
[illegible]	-10	-14	-14	-14	-14
[illegible]	5	6	-4	2	3
[illegible]	7	7	6	7	7
[illegible]	7	7	7	7	7
[illegible]	7	7	7	7	7

†Because of the depressed prior year, this percentage could be achieved even though it is slightly above the maximum growth rate allowed in that year. (See page 5-39.)

4.10 EFFECT ON PETROCHEMICALS

Petrochemical feedstock requirements were met in all years in all schedules. Relatively small differences were observed in the costs of producing incremental amounts of these feedstocks. Schedules L and M show the greatest change in incremental aromatics manufacturing costs because these schedules attempt to substitute high octane refined components for lead over a relatively short time span. Consequently, there is a greater demand for the high octane aromatics during this transitional period.

Although incremental production costs of aromatics did not follow a marked trend in this study, certain aspects of a lead removal program may affect aromatics prices. While construction is under way to substantially increase aromatics production facilities, short term imbalances between supply and demand may exist. Such imbalances could manifest themselves in price instability for short-term aromatics supply.

Other investigators, as well as Bonner & Moore, have published information about rising aromatics costs as a consequence of a program to remove lead from gasoline. Some of these earlier studies showed clearly that added aromatics costs were closely correlated with gasoline pool octane. Increases of a few octane numbers over the present gasoline pool quality have been shown, by calculation, to result in relatively little increase in aromatics cost. As pool octanes rise above a level of about 94 Research Octane Number, the incremental cost of aromatics begins rising very rapidly.

In the present study, pool octane requirements for U.S. refineries are shown to increase relatively little. The target pool octane of 93 RON is below the point at which rapid increases in aromatics costs occur. Another mitigating circumstance offsets the natural trend toward higher aromatics costs with increased octane. This is the trend toward lower gasoline yields which are reflected in the product forecast. These forecasts show that non-gasoline petroleum products are rising more rapidly in demand than is gasoline. Consequently, during the next ten years it can be expected that gasoline yields will decline. This means that there is a smaller pool which must be augmented by aromatics produced from the same crude volume. This reduces somewhat the need for increased aromatics production. This study shows that most refiners will find it economical to build additional reforming and aromatics extraction capacity for gasoline. This demand for extraction capacity, particularly, results in a substantial capacity base to which demands for aromatic petrochemicals can be added. This results in lowered average manufacturing costs by combining two economic uses for pure aromatics, gasoline blending and sales. This reduces the fixed cost portion of total aromatics production costs.

This study goes into more depth than some previous studies in anticipating the sources of future aromatics production. Specifically, this study considers the growth in gas oil cracking capacity to serve future olefins needs at the same time that it considers refinery growth. The cracking of gas oils for light olefins results in substantial yields of by-product aromatics. Combining these effects into a model encompassing both the refinery and basic petrochemical building block industries discloses ways of meeting future aromatics requirements at relatively lower costs than might be expected when considering the refining segment of the industry solely.

It is important that the relation between aromatics cost and gasoline pool octane be clearly understood. This study is premised on an unleaded gasoline grade of 93 Research Octane Number. Should an octane race develop which would force octanes back into the 95 to 100 range, then a substantial increase in aromatics costs would occur. Earlier studies have shown that increases in the order of 50% would be likely if pool octanes rose to the range of 96 to 97.

4.11 CALIFORNIA MODEL RESULTS

Because the refining environment in California is accountably different from that of the rest of the industry, a separate model was used to examine the reaction of California refining to lead reduction. It was expected and indeed found that economic behavior of the California model could be predicted from the U.S. (ex-California) model behavior. That is, added costs and investments for lead reduction in California were expected to be higher but proportional to the costs and investments obtained from the U.S. (ex-California) studies.

To varify this characteristic, a selected set of cases, including a set of California reference cases was developed. From these it was possible to define the proportionality of California to U.S. (ex-California) behavior. The factors shown in Table 37 are the proportionality constants thus obtained.

TABLE 37

COST RATIOS FOR CALIFORNIA ECONOMIC BEHAVIOR

(Ratios = California/U.S. ex-California)

	Gasoline Situation	
	3 Grade	2 Grade
Investment and related costs	1.0	0.9
Non-investment costs	1.5	1.7

Using these factors, it was possible to extend the more complete case analysis of the schedules studied to include the effect of California. In so doing, it was recognized that inaccuracies in the factors as well as the basic assumption of proportionality were greatly ameliorated by the fact that California refining capacity represents only about 12% of the U.S. total.

Construction costs and utility costs were the same for both regional models. Important differences which account for the differing unleaded gasoline costs are the higher octane of California gasoline (higher per cent premium sales) and the heavier crude oils available. The heavier crude refining to produce large volumes of high octane gasoline are more expensive. Although crude cost is lower, the net effect is higher added cost for lead removal.

California currently has more hydrocracking and reforming capacity per barrel of crude capacity than the rest of the refining sector. Lead reduction tends to accelerate this and as a result, this study shows slightly higher aromatics contents in the gasoline pool. It must be noted that no restriction was placed on gasoline hydrocarbon composition.

SECTION 5

DETAIL STUDY METHODOLOGY AND PREMISES

Methodology of this study included several simultaneous efforts which were coordinated to produce the final, industry-wide analysis. A refining and petrochemical modeling team developed the refining models, while other teams established product and petrochemical demand projections, distribution cost analyses, and a process construction industry basis. A brief review of these methods was presented in Section 2. The following is a more detailed and comprehensive account of the study approach.

5.1 STUDY METHODS

1) *LP Model*

The basic study technique employed linear programming models to determine the optimum response pattern of the refining and petrochemical industry to varying profiles of product demand and lead alkyl (TEL) limitations. TEL limitations were determined by EPA-supplied TEL removal schedules, which expressed maximum allowable TEL content for each gasoline grade in each calendar year through 1980. Motor gasoline demand patterns, both for two-grade and three-grade environments, were projected by methods described in paragraph 5.3 of this report, as were demands for light-end refining products, petrochemicals, and distillate and heavy fuels. For each case, the demand patterns and TEL limitations for a subject year were imposed on the models. Plant capacities presumed or calculated to exist at an earlier date were provided as input, and an optimum pattern of new equipment construction and refinery operation was determined.

Previous experience with the stimulus of reduced allowable levels of TEL in gasoline had indicated a high degree of correlation between the reactions of different sized refineries in different geographic locations, excepting California. Thus, one model represented "large" refineries exclusive of California. California's refining industry differed from this norm in the characteristics and behavior, so separate modeling and analysis was done of this industry segment. The response of "small" refineries (smaller than 35,000 barrels per day crude charge) also differs from the patterns exhibited by the balance of the industry, and these were handled separately by techniques of analysis and extrapolation. Finally, that segment of the refining industry not manufacturing gasoline was excluded from consideration in modeling because it is characterized by refining facilities which do not include the reformers or catalytic cracking process units needed to manufacture gasoline.

Linear programming was selected as the basic computational tool for studying these models because of its inherent ability to seek an economic optimum from the myriad and conflicting choices of equipment selection, operating conditions, intermediate feedstock allocation, and finished product blending. The results of these case studies served as a basis for further analysis of proposed schedules' impact on the refining and petrochemical industry, on two-grade vs. three-grade marketing and distribution patterns, on the process construction industry, on the small refiner, and on the consumer. In addition, the results of the earlier case studies served as a basis for developing additional demand and TEL limitation schedules designed to further explore specific facets of the overall technical/economic environment.

2) *Peak Year*

Initial study of the various suggested lead elimination schedules disclosed an important fact about the rapid reduction schedules' effects upon the process construction industry. Rapid lead elimination programs require a major buildup of construction capacity to a sharp peak, followed by a shrinkage in construction business, thereby virtually guaranteeing an induced major business cycle in the industry. The causes of this are quite straight-forward. As allowable lead levels are reduced, new refinery equipment must be built to replace the octane quality formerly supplied by lead additives. The rapid buildup requirement could be well beyond any reasonable expectation of growth potential. At this same time, the increasing proportion of the automotive population represented by post-1971 cars (requiring lower octane gasoline) causes a gradual reduction in the average leaded octane level of the gasoline. If lead levels are reduced too rapidly, the refining industry must install equipment sufficient to meet, on a low-lead basis, the higher average clear octane requirement of an automotive population with a substantial proportion of pre-1971 cars still on the road. As time brings about further attrition of the older cars, the average octane requirement of the automotive population will decline, leaving the refining industry with surplus octane-producing facilities and little incentive or desire to order new process construction. These factors can result in business declines in the process construction industry following the "peak year" of as much as 50%, extending over several years.

The precise timing of this "peak year" condition, where the gasoline clear pool octane reaches a maximum, varies depending upon the rate of lead removal, assumptions concerning the car population, and the increase in usage of low-octane fuels. Nevertheless, the effect is real and may result in a rapid buildup of excessive octane-producing refinery capacity.

Each proposed schedule was therefore examined for the possible presence of a "peak year". Figure 2-1, depicting Schedule G, shows a typical peak situation occurring in 1974. For each selected schedule, the product demand and TEL limitation levels occurring at the peak year were imposed on both models (California, and U.S.A. ex-California), and the expanded equipment capacities (and associated investments) over those required to meet 1969 demand patterns were calculated. These capacities were expressed in terms of the additional capacity required for processing units considered (crude distillation, vacuum distillation, reforming, alkylation, etc.).

A series of cases was then prepared for those years that preceded the peak year. For each year studied, the models were provided with available unit capacities equal to those available at the close of the *prior* year, and were allowed to "build" new equipment as needed to meet the increasing product demands and decreasing allowable TEL levels. In no event, however, was a model allowed to "build" capacity of any unit in excess of that previously established as necessary to meet peak year conditions.

The period between the peak year and the terminal year (1980) was handled in similar fashion. A terminal year run was made, allowing the model to "build" whatever additional capacity (over peak year) was needed to meet terminal year demands. If required, intermediate cases between the peak and terminal years were then run, limiting allowable new facilities construction in this series to those capacities shown to be necessary to meet terminal year conditions. One schedule exhibited no identifiable peak year. For that schedule,(Schedule A), 1980 was run as a peak year, and intermediate years were run using the procedure described for the years preceding the peak year.

3) *Spot Year Analysis*

All schedules were not subjected to the identical series of solutions. For some schedules, peak year only or peak and terminal years only were run. For others, intermediate cases were run. The alternatives of running a complete schedule as a very large "time-staged" linear programming model, or of running without the "look ahead" afforded by the peak year and terminal year runs were both considered.

The time-staged approach, although it would produce a more rigorous mathematical optimum, would have been significantly more expensive. Furthermore, there is serious doubt as to whether the industry itself possesses the flexibility or the infallible foresight to plan for the "perfect" solution which such a model would generate. The "no look ahead" approach, on the other hand, would fail to recognize the level of foresight and advanced planning which occurs in the industry. We believe that the techniques chosen represent fairly the level and effect of advanced planning practiced by the industry.

4) *Facilities Investment*

New facilities investments required by the model solutions were not costed in the specific unit sizes indicated by the model solutions. Instead, investment costs were charged as a pro rata fraction of the cost for typical size refinery units of the types under consideration. For example, the typical size of a crude distillation unit was determined to be 70,000 barrels per day. If, for a particular case, the model indicated that 7000 barrels per day of crude capacity was required, the model refinery would be costed with 1/10th the construction cost of a 70,000 barrels per day unit, not with the estimated construction cost of a 7000 barrels per day unit. This can be considered equivalent to interpreting the solution as implying that, in the year in question, 1/10th of the U.S. refineries built "average" 70,000 barrel per day crude units. The installation of new equipment in an individual refinery is, of course, a sharply discontinuous step function when any individual piece of equipment is considered. Consideration of all new construction within the industry tends to smooth this function considerably, however. The 90% of refiners who presumably did not build crude capacity in the example year would have contributed their share to the overall industry construction pattern through the installation of other needed new equipment.

In practice, refining process capacity is planned and installed to recognize and accommodate three-to-five years of growth. Taken as a whole, the capacity growth of the refining sector would appear to be a relatively smooth function with time. For a specific refinery, however, growth would actually occur as discrete changes. For this study, it was assumed that industry-wide smoothing (via the technique described in the preceding paragraph) tends to reflect an *industry capacity* which results in an *industry excess* no greater than that normally installed.

Added investment is the investment over the reference case for the U.S. refineries (excluding distribution costs). These figures are reported under cost effects in Section 4 on a cost in dollars-per-year basis. The total investment per year, except for the cumulative ten-year investment reported in 1980, is the investment cost per year over 0.2619 (the assumed yearly cost of investment, see Appendix E).

Another consideration must be dealt with to achieve a realistic added investment cost for unleaded gasoline production. This is the fact that unleaded gasoline production facilities will often be combined into a construction program for general expansion. The first assumption of dealing with "average-sized" process units should give a reasonable industry-wide added investment picture. However, the reference schedule uses these same average-sized units, and the investment difference is between differing numbers of these units. In order to approximate a truer added investment cost, the difference between reference and subject case investments was reduced by 30%. This accounts for unleaded gasoline added investments being expended incrementally over a basic expansion program and thereby realizing a lower than average investment cost. The 30% figure is representative of the savings that are calculated by the familiar exponential equation relating capacity and total cost, described elsewhere in the report.

5) *Extrapolation Technique*

Extrapolation of single model behavior to represent industry-wide effects involves assumptions about the character of the refining industry which are derived from experience gained in previous industry economic studies[3]. This experience showed that economic behavior can be expected to follow size-response relationships similar to that represented in Figure 4-1.

Dependence upon employing this kind of relationship implies that characteristics among individual refineries of the refining industry are either uniform or compensating such that uniform (proportional) behavior may be assumed. However, successful extrapolation to *overall* economic behavior does not suggest that it is possible to extrapolate other characteristics of a single model to represent characteristics of the industry. Obviously, known geographic differences in raw stock quality, product demands and economic conditions cause limited sample extrapolation to become sufficiently erroneous to warrant not attempting the extrapolation. For example, extrapolating hydrocracking and cat cracking capacities to national levels implies that local conditions will need both capacities or that local needs will balance out. The former is very doubtful and the latter cannot be tested easily. On the other hand, investment requirements for mid-barrel conversion can be extrapolated without needing to define exactly what kind of process will be involved.

For the purposes of this study, industry-wide economics can be predicted, but details of processing, including process configuration details can not be safely extended to represent industry-wide behavior. The procedures used in extrapolating added costs depend upon the relationship explained in paragraph 5.4

5.2 REFINING AND PETROCHEMICAL INDUSTRY BASIS

5.2.1 Assumptions Pertaining to Process Unit and Blending Data

Petroleum refining processes exist primarily to separate and to modify the hydrocarbons contained in crude petroleum so that these separated streams will satisfy the volume and quality characteristics of fuels and non-fuel products produced from petroleum. These products include gasoline, jet fuels, kerosene, heating oils, diesel fuels, lubes, waxes, asphalts and heavy industrial fuel. In today's refining operations, gasoline is by far the primary product of the refining industry.

The model employed in this study includes representations of all the typical existing processes for separation and conversion of crude oil into salable products. Each process is described in terms of the principal mechanism of representation within the mathematical model.

1) *Crude Distillation*

Crude distillation is the process of separating crude oil into narrow boiling range cuts via fractionation. These separated hydrocarbons can then be further processed in downstream units and/or used directly for product blending.

The model is equipped with a variable which represents the yield structure of the typical composite crude distilled into the fractions used in this model. It includes an optional variable which represents the yields of distilling 12 lb. natural gasoline.

2) *Crude Stream Attributes*

A variety of crude stream attributes are combined during the crude compositing operations of the model to predict the characteristics of certain streams. These attributes include the octane numbers of straight run naphthas, the N2A's†, of straight run naphthas as reformer feeds, the API gravities and characterization factors of gas oils as catalytic cracker feeds, and the sulphur contents of atmospheric distillates, vacuum distillates and vacuum residuum for blending fuels.

†Naphthene plus twice aromatics, used as a reforming feed quality characteristic.

3) *Vacuum Distillation*

Vacuum distillation separates reduced crude coming from the crude unit into defined boiling range fractions via distillation under vacuum conditions to avoid thermal cracking of these heavier boiling hydrocarbons. These fractions can then be processed further or used in blending for fuel products.

The model has a single variable representing distillation of the reduced crude from the composited typical crude into the boiling range fractions used.

4) *Thermal Cracking*

Thermal cracking is a process of cracking long hydrocarbon molecules into smaller molecules by exposing the molecules to high temperatures for a long period of time. The lighter molecules produced (gas and naphthas) generally require further processing before they can be used in final products; the heavier molecules can often be blended directly into fuel oils.

The thermal cracker is assumed in this study to represent cracking of virgin gas oil feeds ranging from 20 to 27 API gravity. Linear interpolation between these two is permitted by the model. The thermal gasoline is optimally depentanized in the model.

5) *Coking*

The delayed cokers normally found in U.S. refineries crack vacuum residuum into lighter hydrocarbons by exposure to high temperatures for an extended time period. The liquid products from the coker are similar to that of thermal crackers.

The model contains yield patterns for vacuum residuums, steam cracked tar, cat cracker slurry, heavy vacuum gas oil, thermal cracked tar, and visbreaker tar. The model also contains a Conradson carbon correction to reflect the proper yields on feeds from dependent crude sources. The light coker naphtha produced is optimally depentanized.

6) *Visbreaking*

Visbreaking is a process similar to thermal cracking, except that high temperature retention time is greatly reduced. It is used primarily as a means of reducing viscosity of the feedstock, not as a means of cracking to lighter material. The products can be further processed, or the heavier gas oils can be blended into final products. This process is not common to the modern U.S. refinery and is being phased out by many of the older refineries.

The model contains a single variable representing visbreaking of vacuum residuals into the appropriate products. The visbreaker gasoline is allowed to be depentanized.

7) *Catalytic Cracking*

The catalytic cracker selectively cracks gas oil feeds into lighter molecules by exposing the gas oil to a catalyst under high temperatures. The products include olefinic gasolines of high octane and light olefins for alkylation feedstocks.

The model assumes a basic feedstock quality of the following properties:

- 796° average boiling point.
- K factor of 11.5.
- Operating at a 60% conversion with 100% zeolite catalyst.

A set of variables represents the collection of various feedstocks into a cat cracker feed pool, along with their average boiling point and K factor quantities. The basic yield structure is then adjusted by a K factor and average boiling point corrections. The model is permitted to increase severity upwards to a maximum of 75% via another corrector operation. Still another corrector reflects permission to add alumina instead of zeolite catalyst. The model also reflects the operation of splitting full range catalytic gasoline into a "C_5 to 250" and a "250 and heavier" fraction. The operation of depentanizing a catalytic gasoline is included as well.

8) *Steam Cracking*

This process is often referred to as an olefin plant, or ethylene plant, as the primary products are ethylene and other light olefins. The process cracks feeds ranging from ethanes to gas oils under high temperatures and in the presence of steam.

Although large refineries can and do have steam cracking facilities, most steam cracking capacity exists in petrochemical plants. The model used in this study includes steam cracking as a process which can take refinery intermediate streams as charge stocks to produce ethylene, propylene, and butadiene and return to the refinery the unused butylenes, gasoline, gas oil and tar resulting from the steam cracking operation. The steam cracking process is permitted to vary the severity of cracking naphthas and gas oil feeds to the steam cracker.

9) *Hydrocracking*

Hydrocracking is a process for cracking heavy gas oils and residuals under very high pressures in the presence of hydrogen, using special catalysts. This process is used to convert high boiling stocks to lower boiling stocks, and is similar to cat cracking except that the products have quite different properties than those from catalytic cracking.

The model permitted hydrocracking of all gas oils. Charge stocks included coker gas oil, light cycle oil from the cat cracker, light vacuum gas oil, steam-cracked gas oil if present, a light virgin gas oil, visbreaker gas oil, heavy vacuum gas oil, gas oils from residuum hydrocracking, and virgin kerosene. For each of these feeds, three separate yield structures representing severity levels are called gasoline, jet fuel, and distillate operations.

A separate operation is also modeled reflecting the hydrocracking of topped crude or vacuum residuum with the assumption that this would be a separate, more expensive unit than the one noted above.

10) *Residuum Hydrofining*

Residuum hydrofining is the desulfurization of heavy gas oils and residuals with moderate cracking. The products often can be blended directly or processed further. The model reflects hydrofining of reduced crude and vacuum residuum.

11) *Vacuum Unit for Hydrofined/Hydrocracked Residuals*

In design and purpose, this is similar to the vacuum unit for reduced crude from the crude unit. The model has the ability to build vacuum unit capacity for further fractionation of 650+ material from either residuum hydrocracking or hydrofining.

12) *Gas Oil/Kerosene Hydrogen Treating*

Hydrogen treating of 375°F to 650°F material takes place under moderate pressure and hydrogen atmosphere in the presence of a catalyst. The process removes sulfur, nitrogen and other impurities, and saturates most unsaturated molecules. The model allows treating of all the streams in the 375° to 650° boiling range. The variables represent yields based on assumed properties of each feed.

13) *Naphtha Hydrogen Treating*

Hydrogen treating of naphthas is similar to that of gas oils, except that the feed is lighter. The primary purpose of this unit is to prepare reformer feedstock to protect the expensive reformer catalyst from impurities. The model contains numerous variables representing hydrogen treating of all potential reformer feeds. These include virgin straight run naphthas, hydrocrackates, thermal and cat cracked gasolines, and heavy raffinate from aromatics extraction.

14) *Reformer*

The catalytic reformer is a process to convert nonaromatics to aromatics in a hydrogen atmosphere over a platinum or platinum-rhenium catalyst. The products are prime gasoline blending components and/or aromatic extraction feedstocks. The model reflects severity levels from 85 to 105 RON clear and a correction of yields based on feedstock properties. Reformate was permitted to be blended into gasoline or was fed to aromatics separation facilities for recovery of pure aromatics.

15) *Alkylation*

The alkylation process produces prime gasoline blending components by combining isobutane with light olefins (C_2, C_3, C_4, or C_5), using an acid catalyst. The resulting product is a gasoline component with relatively high clear octanes.

The process modeled is the HF acid process. The yield structure was designed for alkylation of propylene, butylene, pentylenes and steam cracked C_4's. Because of its relatively high cost, ethylene alkylation was represented in the model as a separate process and its use was restricted to ethylene feed.

16) *Isomerization*

Isomerization is used to convert straight chain gasoline materials into their highly branched isomers. By converting some of the light materials to their isomers, an increase in octane rating is achieved.

The model depicts a yield structure for butane, pentane and hexane isomerization, each processed through separate facilities.

17) *Merox Treating*

Merox treating of gasoline and lower boiling fractions removes mercaptans by converting mercaptans to disulfides. All sulfur-bearing gasoline blending streams were represented as requiring Merox treating.

18) *Aromatic Separation*

Separation of aromatics is accomplished by a combination of solvent extraction and fractional distillation steps on reformate. The main purpose of aromatic separation is preparation of benzene, toluene and xylene as petrochemical feedstocks. The other purpose is the preparation of high-octane blend stocks.

Process yields in the model depicted the performance of a full aromatics separation complex. In this process, full range reformate is charged to a tower whose overhead is the benzene fraction. The bottoms from the tower feed a second tower whose overhead is the toluene fraction. The bottoms from the toluene tower may go either to gasoline blending or to a third tower whose overhead produces incidental xylenes and whose bottoms are heavy aromatics. Aromatics separation was limited to 95 severity reformate or higher.

19) *Hydrodealkylation*

Hydrodealkylation of higher boiling aromatics produces benzene. This is not a common practice in the industry, and only a small amount of the benzene production results from this process. The model represented two feedstocks, toluene and xylene, with their appropriate yields.

20) *Hydrogen*

Hydrogen manufacture and purification are two separate processes employed to meet demands for high purity hydrogen. The model's predominant source of hydrogen is the reformer, with some of the more severe hydrocracking requiring hydrogen purer than commonly produced from reformers. This pure hydrogen can be produced either through purification or through hydrogen manufacture.

21) *Sulfur Plant*

The sulfur plant produces elemental sulfur from hydrogen sulfide. All hydrogen sulfide produced as a by-product from other refinery operations in the model was processed through the sulfur plant.

22) *Miscellaneous Units*

Besides the common units currently in operation in the U.S., the model included some processes that have been demonstrated commercially although currently not used extensively. However, none of these processes (listed below) was selected in any of the cases studied.

- Catalytic polymerization.
- Propylene disproportionation.
- Ethylene alkylation.
- Isobutane cracking.

23) *Blending*

The gasoline blending properties of all potential gasoline blending components were represented as linear blending characteristics. Octane blending values were supplied for each potential gasoline blending agent for regular grade and for premium grade blending. This included octane blending values for both research and motor octane methods, with 0, 0.5, 1.0, 1.5, 2.0, 3.0 and 4.0 grams of lead per gallon. In addition to octane blending values at various lead levels, the model also included vapor pressure and distillation blending characteristics of each component. These characteristics were the percent distilled at 160, 210, 230, 330, and 360 degrees Fahrenheit, respectively. Table 38 presents the specifications imposed on each grade of gasoline.

The model data base also provided separate blending recipes for LPG, for JP4 turbine fuel (two recipes), for "special naphtha" (assumed to include solvents and other special products) and for extremes in permissible composition of propylene used as chemical raw materials (two recipes).

TABLE 38

GASOLINE BLENDING SPECIFICATIONS

	Premium	Regular	New "93"
Reid Vapor Pressure, Max.	10.3*	10.1*	10.1*
Percent Distilled at			
160°F, Min.	18	18	18
160°F, Max.	33	35	35
210°F, Min.	39	39	39
210°F, Max.	54	57	57
230°F, Min.	49	49	49
330°F, Min.	84	84	84
330°F, Max.	96	96	96
Research Octane Number, Min.	100	94	93
Motor Octane Number, Min.	92	86	85

*California model imposed 8.25 max. RVP to comply with recent state legislation.

The flash, viscosity-blending and sulfur contents of materials potentially available for residual fuel oil blending were supplied to the model. Flash and the percent distilled at 350°F and 400°F were supplied for distillate blending stocks as well as two blending characteristics to control composition. The first of these was used to limit the percent of heavy straight run in any distillate fuel. The second controlled the amount of virgin kerosene which could be blended into the distillate pool.

5.3 DEMAND FORECASTS

5.3.1 Automotive Gasoline Demand Projection Basis

1) *Engine Fuel Octane Requirements*

In 1970, certain automotive manufacturers publicly declared that their future cars, starting in 1971, would be satisfied with 91 RON gasoline. Thus, the RFP for this study defined a 91 RON quality for future unleaded fuels. After discussion with several industry groups it was concluded that the 1971 cars intended for use with 91 RON fuel did not obtain knock-free performance on this fuel to the extent customarily expected for consumer satisfaction. Consequently, the EPA task force changed the RFP premise to 93 RON as the anti-knock quality for unleaded fuel. The following discussion of this point was developed by Mr. L. H. Solomon.

Public announcements made by automotive manufacturers regarding fuel requirements for 1971 automobile models suggested that a 91 Research Octane fuel would satisfy all new-car production. Unfortunately, these statements were an oversimplification of a very complex problem. It might have been more appropriate for the automotive companies to suggest that 1971 models would be designed with an 8.5-to-1 compression ratio. Unfortunately, it is very difficult to specify in advance the actual octane requirement of an automobile population.

Figure 5-1 illustrates the distribution of Research Octane Number requirements for automobiles as a function of compression ratio[4]. It may be noted that the octane requirements for cars with various compression ratios have been adjusted for the impact of unleaded fuels. At an 8.5-to-1 compression ratio, the level selected by General Motors Corporation for most of their 1971 automobiles, approximately 10% of the cars could be satisfied with a fuel as low as 86 RON, but 2% will require over 96 RON. This variability of octane-number requirement is strictly a function of the manufacturing tolerances of various parts of the engine. In previous model years, only about 70% of the nominal regular fuel engines were technically satisfied† with prevailing regular grade gasoline. It has been estimated that general consumer satisfication would be approximately 15% higher than technical satisfaction as measured by a trained test driver. On this basis, we could anticipate 100% consumer satisfaction with the 1971 automobiles using a 94 RON fuel.

---

†It should be noted that "satisfaction" in this instance describes the percentage of automobiles which can be operated without developing a knock perceptible to a trained test driver.

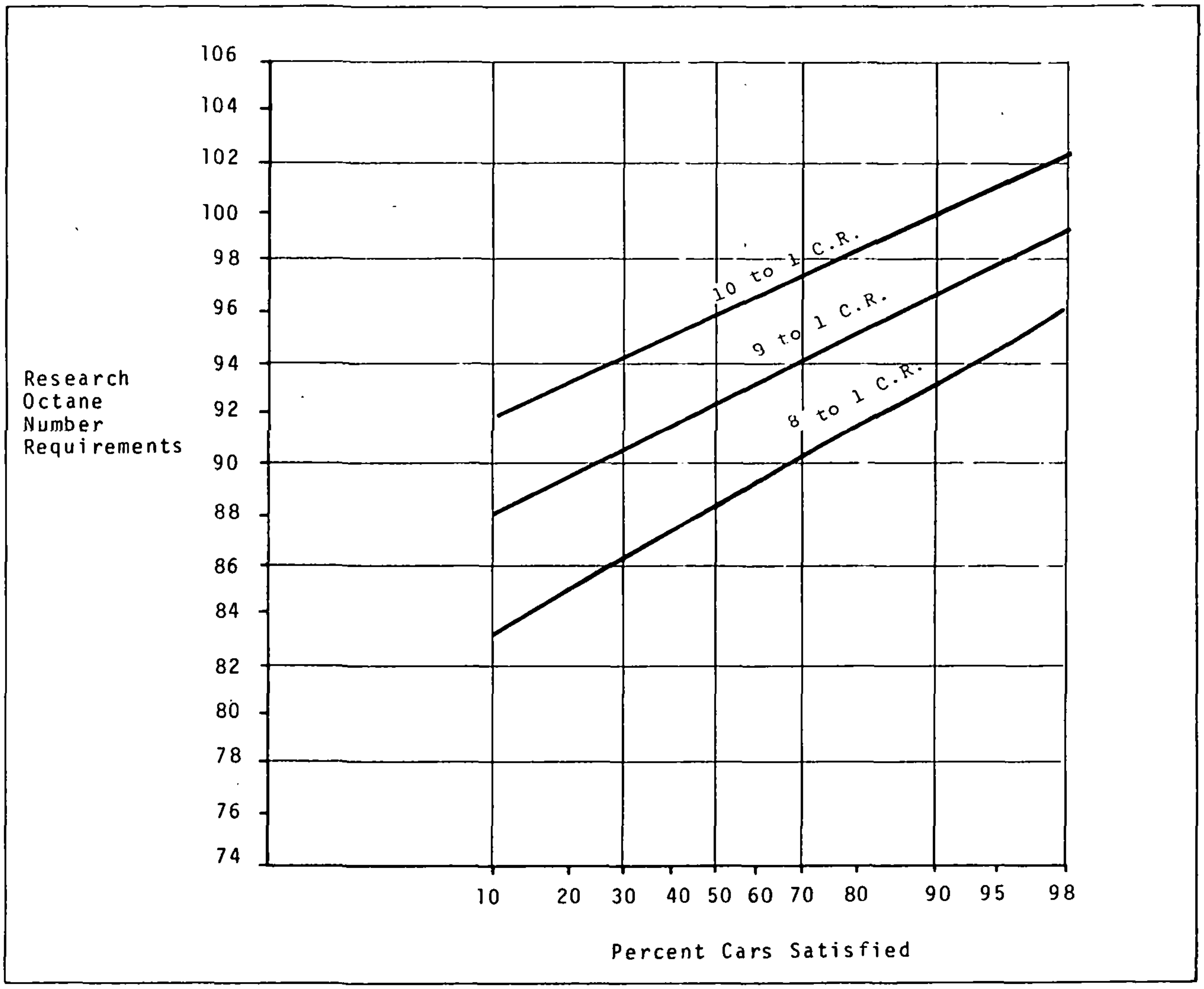


Figure 5-1. Distribution of Research Octane Number Requirements
As Function of Compression Ratio

Satisfaction on the part of the consumer is masked to some extent by the phenomenon of overbuying, i.e. the tendency of a large number of consumers to voluntarily select a premium fuel for some automobiles which can be technically satisfied with prevailing regular grade fuel.

- Implications of Unleaded Fuel Octane Levels

In light of the available information on octane level requirements for 1971 automobiles, three possible study approaches were possible.

First, it could have been assumed that the automotive industry would be forced into a reduction of compression ratios to ensure customer satisfaction with 91 RON unleaded fuels. Assuming a 95% customer satisfaction is to be the selection criterion, this would restrict future automobile engine manufacture to a compression ratio of approximately 7.2-to-1. However, based on available literature, such a reduction in compression ratio would reduce the thermal efficiency of an automotive engine by approximately 5%. This reduction in thermal efficiency would result not only in increased fuel consumption, but in reduced performance of future automobiles, a reduction certain to be poorly received by the general public.

An alternate method would have continued the study of a 91 RON unleaded grade, but would have required a 94 RON unleaded grade in 1975, when catalytic systems will be installed. It would not seem reasonable to add a fourth grade in view of the considerable investments required on the part of marketing and distribution companies to segregate an additional grade of motor fuel. If the prevailing regular grade fuel in 1975 is also required to be unleaded, we would find that not only the new cars, but all of the pre-1975 automobiles designed for operation on regular fuel would be forced to utilize unleaded gasoline. This would sharply increase the demand for unleaded fuel in 1975 to a point that may exceed the maximum capability of the petroleum industry. While such a regulation could be imposed upon the petroleum industry, it does not appear to be a "most reasonable" basis for impartially measuring the economic impact of lead removal.

A third course of action would have been to select an unleaded grade of fuel to be imposed upon the market place, a grade which would result in general consumer satisfaction with all engines having a nominal 8.5-to-1 compression ratio. Again using the criterion that 95% of the automobiles must be satisfied on a consumer basis, and translating that to an 80% technical satisfaction, it would appear that the 8.5-to-1 compression ratio automobile would require a 93 RON unleaded fuel. Though some 5% of the automobiles would not meet consumer satisfaction, some portion of these cars could be satisfied by a very high octane unleaded grade, such as Amoco's Super Premium. The remaining motorists would simply have to adjust to a less than completely satisfactory performance of their automobile engines.

- Octane Grade Distribution

Based on preliminary test data available on 1971 automobile engines, it appears likely that the imposition of a 91 octane unleaded fuel on the petroleum industry will not yield the minimum economic impact of removing lead from motor fuel. The variability in automobile engine manufacture suggests that adoption of a 93 octane unleaded fuel would not permit higher compression ratios than those of the 1971 models, but would lead to a greater consumer satisfaction in the performance of cars such as those offered by major manufacturers in the 1971 model year. While a 91 RON unleaded fuel could be required, an additional, higher octane unleaded grade would also be necessary in view of the possibility of catalytic reactor systems which can only perform satisfactorily on unleaded fuel. It is doubtful that such a situation would describe the most likely occurrence within the petroleum and automotive industries unless fuel octane number and/or automotive compression ratio are specified by the Federal Regulations.

The detailed distribution of grade requirements used as a basis for this study is outlined in Table 39.

2) *Automotive Gasoline Production Requirements*

The gasoline production requirements were forecasted for three major categories of marketing conditions:

- A base case assuming no lead removal or engine revision programs.
- Cases involving octane requirement reduction on new cars, exhaust conversion reactors on 1975 models and later, and two grades of gasoline produced.
- Cases similar to the foregoing except three grades of gasoline are produced.

TABLE 39

BASIS FOR GRADE DISTRIBUTION - AUTOMOBILES AND LIGHT TRUCKS

3-Grade

Pre-1971 Cars	45.4% Premium 100 RON 54.6% Regular 94 RON
1971 through '74 Cars	50% Regular 93 RON 50% Regular 94 RON
Post 1974 Cars	100% Regular 93 RON

2-Grade

Pre-1971 Cars	45.4% Premium 100 RON 54.6% Regular 94 RON
1971 through '74 Cars	100% Regular 94 RON
Post 1974 Cars	100% Regular 94 RON

Notes:

1. Pre-1971 cars are assumed to continue past buying habits. Though many could operate satisfactorily on 93 RON clear, no incentive exists to shift to the presumably higher cost unleaded grade.

2. 1971 - 75 cars are all assumed to be 8.5-to-1 compression ratio. About 95% could be satisfied with 93 RON clear. However, *only 50%* will buy 93 clear because of:

   - Fear of valve failure with unleaded fuel.
   - Established buying habits.
   - Likely high cost of 93 RON unleaded fuel.

   In a 2-grade market, all 1971 - 75 cars buy 94 RON clear or low lead because it is the only regular grade available and should be cheaper than 100 RON leaded.

3. Post-1975 cars all buy clear fuel either 2-grade or 3-grade because of legal restrictions and catalyst intolerance to lead.

4. Heavy-duty trucks burn 94 RON leaded in 3-grade and 94 clear in 2-grade for all years because of minimum cost.

National demand forecasts for gasolines, under the above marketing conditions (see Table 40) were based also upon the following assumptions[5]:

a) The total vehicle miles driven in each year were calculated from data supplied by the Environmental Protection Agency, using the following equations:

$$\text{billions of car miles} = -137.54 - 36.86\,(y) + 1.2073\,(y^2) - .0067\,(y^3)$$

$$\text{billions of truck miles} = -434.95 + 20.863\,(y) - .299\,(y^2) + .00184\,(y^3)$$

where y = calendar year - 1899.

b) The truck miles calculated in this way represent all classes of trucks. These miles were distributed among three classes of trucks in the following proportions:

- Light duty 45.1%
- Heavy duty 42.8%
- Others (non-gasoline) 12.1%

c) The miles driven were converted to gallons assuming the following miles-per-gallon figures:

Vehicles	MPG
Base Case	
All cars	14.0
All light duty trucks	11.0
All heavy duty trucks	8.5
Lead Removal Cases	
Cars, model 1970 and earlier	14.0
Cars, model 1971 - 1974	(14.0)(.95)†
Cars, models 1975 - later	(14.0)(.88)††
Light duty trucks, 1970 and earlier	11.0
Light duty trucks, 1971 - 1974	(11.0)(.95)†
Light duty trucks, 1975 and later	(11.0)(.88)††
Heavy duty trucks	8.5

†Compression ratio drop for post-1971 automobiles is reflected by a 5% penalty.

††Catalytic reactor performance effect for post-1975 automobiles is reflected by a 12% penalty.

TABLE 40

NATIONAL DEMAND FORECAST FOR GASOLINE

Marketing Category	Billions of Gallons Per Year			
	93 Octane	94 Octane	100 Octane	Total
Three-Grade Subject Cases				
1971	6.2	55.8	29.8	91.8
1972	11.9	57.5	26.0	95.4
1973	17.4	59.2	22.4	99.0
1974	22.4	60.8	19.3	102.5
1975	35.3	55.6	16.2	107.1
1976	47.4	50.9	13.4	111.7
1977	58.9	46.6	10.6	116.1
1978	69.4	42.8	8.1	120.3
1979	78.9	39.2	5.9	124.0
1980	88.4	35.9	4.1	128.4
Two-Grade Subject Cases				
1971		62.0	29.8	91.8
1972		69.4	26.0	95.4
1973		76.6	22.4	99.0
1974		83.2	19.3	102.5
1975		90.9	16.2	107.1
1976		98.3	13.4	111.7
1977		105.5	10.6	116.1
1978		112.2	8.1	120.3
1979		118.5	5.9	124.0
1980		124.3	4.1	128.4
Two-Grade Reference Case				
1971		56.1	35.1	91.2
1972		58.0	36.2	94.2
1973		59.8	37.4	97.2
1974		61.7	38.5	100.2
1975		63.5	39.7	103.2
1976		65.3	40.8	106.1
1977		67.1	41.9	109.0
1978		68.9	43.1	112.0
1979		70.7	44.2	114.9
1980		72.4	45.2	117.6

c) Because the average miles-per-gallon varied with year of manufacture in the lead removal cases, it was necessary to estimate the mileage driven by vehicles of each model year. These were based on Table 41.

TABLE 41

MILEAGE VERSUS VEHICLE AGE

Age of Vehicle (Years)	% of Total Miles Driven in Vehicle Class Assigned to Vehicle Age Group	
	Cars	Light Duty Trucks
1	15.74	10.0
2	13.69	9.5
3	12.02	9.0
4	10.04	8.5
5	9.36	8.0
6	8.18	7.5
7	7.55	7.0
8	6.52	6.5
9	5.24	6.0
10	4.31	5.5
11 and older	7.35	22.5

d) The requirements of gasoline by grade were assumed to depend upon vehicle type, grades offered, and model year according to the proportions shown in Table 42.

TABLE 42

GASOLINE CONSUMED PROFILES

Case and Vehicle	% of Gasoline Consumed in Each Octane Grade		
	93	94	100
Base Case			
Cars and light duty trucks		55.6	45.4
Heavy duty trucks			
Lead Removal, two grades			
Cars and light duty trucks, 1970 and older		55.6	45.4
Cars and light duty trucks, 1971 - 1980		100	
Heavy duty trucks		100	
Lead Removal, three grades			
Cars and light duty trucks, 1970 and older		55.6	45.4
Heavy duty trucks		100	
Cars and light duty trucks, 1971 - 1975	50	50	
Cars and light duty trucks, 1975 and later	100		

e) Gasoline consumption in California has for several years been distributed between premium (100 octane) and regular (94 octane) in a 60/40 ratio in contrast to a 40/60 ratio for the U.S. as a whole. (Gasoline production in California exceeds the consumption.) Approximately 10.5 percent of the total U.S. gasoline consumption is in California. It was assumed that the California demand for motor fuels was supplied by California refineries and the production in excess of California requirements was in the same proportion (among grades) as the total of the U.S. The California consumption was assumed to be 60/40, premium/regular, for all cars and light duty trucks in the base case and for 1970 and earlier models in the lead removal cases. All other classes of vehicles were assumed to have the same requirements by grade as defined in d) above.

5.3.2 Aeronautical and Distillate Fuel Demand Projection Basis

1) *Naphtha Jet Fuel Projection*

Government purchases of Naphtha Jet Fuel (JP4) were 207,773,000 bbls in February 1969 (83,218,000 were delivered in the U.S.) and 177,173,000 bbls (81,555,000 bbls in U.S.) in February 1970[6]. Government purchases of JP4 were projected to increase to 181,866,000 bbls in February 1971[6]. No switch from naphtha based jet fuels to kerosene base is expected in the near future[7].

The Air Force, which is the only major consumer of JP4, has experimented with a kero-jet fuel (JP8) but is dissatisfied with smoke point specification performance.

No basis exists for predicting a switch from naphtha jet fuel to kerosene base in the time period 1971 - 1980. The Air Force has successfully resisted such a switch for many years.

Therefore, as the Viet Nam conflict declines, JP4 demand will probably fall back to 1965 standards, which are generally consistent with Government U.S. deliveries in 1969 and 1970. (Jet fuel production history is shown in Table 43. This volume will probably not exceed 82,000,000 bbls.

TABLE 43

NAPHTHA JET FUEL PRODUCTION HISTORY

Year	Domestic Production[8] (Thousands of Bbls)	Growth Rate
1969	104,748	13.49%
1968	121,165	10.50%
1967	109,650	22.55%
1966	89,473	8.56%
1965	82,416	-

2) *Kerosene Demand Projection*

Government purchases of JP5 (kerosene based jet fuel primarily used by the Navy) dropped from 24,931,000 bbls in 1969 to 21,453,000 bbls in 1970[6]. Total consumption of kerosene based jet fuel rose 17.7% from 1967 to 1968 and 13.7% from 1968 to 1969. Almost all commercial jets use kerosene based fuel[7]. Kero-jet fuel could increase 12%/year, but may be retarded by further introduction of jumbo jets. Kerosene production history is summarized in Table 44.

TABLE 44

KEROSENE AND KEROSENE JET FUEL PRODUCTION HISTORY

Year	Domestic Demand[8] for Kerosene (Thousands of Bbls)	Domestic Demand[8] for Kerosene & Kero Jet (Thousands of Bbls)	Growth Rate
1969	101,738	318,690	8.39%
1968	100,545	204,013	11.95%
1967	99,061	262,596	15.77%
1966	100,849	226,822	12.41%
1965	93,149	201,788	-

Fiscal Year 1971 Government purchases of JP5 will continue to increase at approximately the same rate as in fiscal 1970[6]. One outside source predicts an average growth in kerosene jet fuel of 14% from 1971 through 1975[9].

Assuming no switch over from naphtha based jet fuel, the kerosene jet fuel demand should grow at about 12%/year for the years 1971 - 1980. Other demand for kerosene will stay essentially the same at 100,000,000 bbls/year. Total annual demand in 1980, then, would be 774,000,000 bbls.

If JP4 is discontinued in favor of a kerosene fuel, the annual kerosene demand would be increased by about 80,000,000 bbls/year.

3) *Aviation Gasoline Demand Projection*

Government purchase of aviation gasoline dropped from 21,506,000 bbls in February 1969 to 15,954,000 in February 1970[6], but will increase to about 16,630,000 bbls in February 1971. *Aviation gasoline demand* is expected to increase during the 1970's as more private aircraft are used. *Domestic private demand* is expected to grow 65% from a 1969 level of 597 million gallons (14,214,000 bbls) to 985 million gallons (23,500,000 bbls) in 1981[10]. Aviation gasoline production history is summarized in Table 45.

TABLE 45

AVIATION GASOLINE PRODUCTION HISTORY

Year	Domestic Production[A] (Thousands of Bbls)	Growth Rate
1969	26,460	-16.17%
1968	31,563	-14.86%
1967	37,074	-10.11%
1966	41,244	-15.08%
1965	48,569	

The domestic production of aviation gasoline will not exceed 1969's figure of 26,460,000. Continental U.S. production will continue to meet average demand requirements of less than 25,000,000 bbls/year.

4) *Distillate Fuel Oil Demand Projection*

Imports of distillate increased 165.9% over the 10-year period 1959 - 1968 (1968's imports were 46,947 thousand bbls)[11]. Total distillate demand (imports and domestically produced) in 1968 was 873 million bbls[11]. Both total distillate demand (5.29% increase in 1968 over 1967)[11] and its major market, home heating, will continue to grow steadily. The next largest market, diesel highway fuel (127.290 million bbls in 1968)[12], appears to be growing more rapidly. Demand growth for distillate has been predicted as just over 5%/year[9] and 4.4%/year[13].

There is no well-defined basis for predicting a rate of growth for distillate supplied by continental U.S. refineries. The demand for distillates should continue to grow at an average of approximately 5%/year for the time period 1971 - 1980. This demand will probably be met by at least 846,863,000 bbls (1969 production) from continental U.S. refineries. At this time, an average of 14,600,000[14] bbls can be imported. Distillate production history is summarized in Table 46.

TABLE 46

DISTILLATE PRODUCTION HISTORY

Year	Domestic Production[8] (Thousands of Bbls)	Growth Rate
1969	846,863	0.09%
1968	839,373	4.34%
1967	804,429	2.51%
1966	784,717	2.57%
1965	765,071	

5) *Aeronautical Fuel Demand Summary*

Table 47 summarizes the projected demands for all aeronautical and distillate fuels.

TABLE 47

DISTILLATE PRODUCT BLEND
(MILLIONS OF BBLS)

Product Location	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
*Light Distillate Fuel**												
California	51	55	60	65	71	77	85	93	102	113	124	137
All Other U.S.	268	290	314	342	373	407	446	489	537	592	652	720
Total U.S.	319	345	374	407	444	484	531	582	639	705	776	857
Naphtha Jet Fuel**												
California	26	24	22	21	21	21	21	21	21	21	21	21
All Other U.S.	79	73	68	62	62	62	62	62	62	62	62	62
Total U.S.	105	97	90	83	83	83	83	83	83	83	83	83
Heavy Distillate Fuel***												
California	55	58	61	64	67	70	74	78	82	86	90	94
All Other U.S.	791	831	872	916	961	1,010	1,060	1,113	1,169	1,227	1,288	1,353
Total U.S.	846	889	933	980	1,028	1,080	1,134	1,191	1,251	1,313	1,378	1,447

Base Assumption - "California" will behave "like all other U.S." in regard to these products.

* For LDF: Assume 32% of total is kerosene, which is a stable demand; and 68% is kero-jet which will grow @ 7.5 to 12%/year.
California then has 16.3 mm bbls fixed and 34.7 will grow @ 12%/year.
All other then have 85.5 mm bbls fixed and 182.5 will grow @ 12%/year.

** For JP4: Assume 7.5% decline first 3 years then no change.

***For Distillate: Assume 5% growth.

5.3.3 Petrochemical Demand Projection Basis

Table 48 presents the national forecasts of petrochemical demands for the period 1971 - 1980. Bases for individual petrochemical projections are described below.

1) *Ethylene Demands*

An examination of several published sources reveals forecasts for domestic ethylene demand growth rate range from 9%[15] to 11%[16,17,18] per year from 1970 to 1980. Similar ranges of estimates exist about 1970's demand, e.g., from 15.0[17] to 17.2[15] billion pounds.

The maximum growth rate, 11%, applied to the 1969 usage (14.25 billion pounds) established for prior Bonner & Moore studies, produces a 1970 demand of 15.8 billion pounds. Growth of this demand at a constant 11% over the years 1970-80 will result in a computed 1980 demand of 45.3 billion pounds, which is comparable to that forecast by Struth[16] (45 billion pounds) and by Mills and Tosh[19] (44.3 billion pounds maximum).

TABLE 48

NATIONAL DEMAND FORECAST FOR PETROCHEMICALS

Year	Annual Demand (Billions of Lbs.)					
	Ethylene	Propylene	Benzene	Toluene	Xylene	Butadiene
1971	17.5	9.0	9.4	1.0	2.6	3.2
1972	19.5	9.9	10.3	1.1	2.9	3.4
1973	21.7	11.1	11.4	1.2	3.2	3.6
1974	24.1	12.3	12.5	1.3	3.5	3.8
1975	26.8	13.6	13.8	1.4	3.8	4.0
1976	29.8	15.1	15.1	1.5	4.2	4.2
1977	33.1	16.8	16.6	1.6	4.7	4.5
1978	36.7	18.7	18.3	1.8	5.1	4.8
1979	40.8	20.7	20.1	1.9	5.6	5.1
1980	45.3	22.9	22.2	2.1	6.2	5.4

At this rate, the 1975 demand of 26.8 billion pounds agrees reasonably well with Collinswood[17] (24 billion pounds) and Lewis[20] (25-28 billion pounds). If a growth rate of 11%/year were applied to Collinswood's 1970 demand projection (15 billion pounds), the resultant 1975 demand would be 25.3 billion pounds and the 1980 demand would be 42.6 billion pounds. Other literature examined[15] quotes Donald O. Swan, President of Esso Chemicals, as predicting a 9% growth on a 1970 base of 17.2 billion pounds, resulting in a 1980 demand of 39 billion pounds. Humble Oil predicts[21] a 9% growth from 1970 to 1975 and an increasing growth rate of 10+% from 1975 to 1980.

The EPA study used an 11% growth rate for ethylene. This rate is recognized by general consensus in the literature through 1975. Past 1975, 11% appears to be as well recognized as any other rate. For two decades, forecasters have been predicting a decline in ethylene growth. While this decline may finally arrive in the mid-70's, no literature referenced gave a reason to expect this to happen.

2) *Propylene Demands*

Propylene growth rates have been forecast at 9%[17], 11.6%[19], and 7+%[22] for the period 1970-1980. These rates have been applied to various base 1970 demands, all in excess of 7 billion pounds. Forecast demand by 1975 range from 11.2 billion pounds to 17.2 billion pounds, and by 1980 they range from 16.4 billion pounds to 30.3 billion pounds.

A growth factor of 11%, applied to Bonner & Moore's 1969 demand estimate of 7.3 billion pounds, produced a calculated 1975 demand of 13.6 billion pounds and a calculated 1980 demand of 22.9 billion pounds. These demand forecasts are higher than those established by Collinswood and Ockerbloom[6] but within the range set by Mills and Tosh.

No evidence was observed that would indicate any predictable drop in propylene demand in the 1970's. The EPA study therefore used an 11% growth rate, which is slightly less than that established by Mills and Tosh, to establish an acceptable propylene demand forecast through the period 1970-1980. Use of an 11% growth rate on a 1969 base of 7.3 billion pounds produces a 1975 demand of 13.6 billion pounds and a 1980 demand of 22.9 billion pounds, which are close to Humble Oil's forecast of 13.4 and 21.1 billion pounds, respectively.

3) *Butadiene Demand*

The general absence of literature which forecasts demand growth for butadiene indicates its tendency toward oversupply and fixed market position. Demand for synthetic rubber, a major consumer of butadiene, is expected to grow at 4%/year in the 1970's[15]. New uses for butadiene such as ABS resins may grow in the 1970's, however. These uses appear to be reflected in Collinswood's forecasts of 3% growth through 1975, then a rapid acceleration to 8% through 1980. Mills and Tosh forecast growth ranges for butadiene of 3.9 to 5.2 billion pounds by 1975 and of 4.2 to 7.5 billion pounds by 1985. Humble Oil's forecasts, 4.3 billion pounds by 1975 and 5.3 billion pounds by 1980, fall within the Mills and Tosh ranges.

A growth rate of 6%/year applied to a 1969 base of 2.96 billion pounds provides a demand forecast for the years 1970-1980 which agrees closely with Humble Oil's projections. These forecast demands fall within the ranges established by Mills and Tosh and compare with the 1980 demand forecast by Collinswood.

4) *Petrochemical Benzene*

Because of its potential use as a gasoline blending material and because of its multiple chemical uses, demands for benzene are difficult to forecast. A literature search reveals forecasted growths from 4%[23] to 7%[21,24] per year through 1975 and in excess of 7% for the latter 1970's. Actual demand quantities are forecast as growing from 8.0[25,26] to 10.3[23] billion pounds per year in 1970, to 12.8[23] to 13.3[21] billion pounds in 1975, and to 14.0[24] to 19.2[21] billion pounds in 1980.

Since petrochemical uses of benzene have grown rapidly, it appears reasonable to assume demands will continue in the early 1970's so that it will reach a consensus quantity of approximately 13 billion pounds by 1975. And since no author gives reasons for curtailment of this growth in the later 1970's, and indeed one source[23] shows an increase in the period 1975-1980, it seems reasonable to apply a growth rate to a base 1969 demand of 7.4 billion pounds (generated for previous Bonner & Moore studies), which will provide a calculated 1975 demand of approximately 13 billion pounds, and to continue this growth through 1980. A growth rate of 10% will produce a calculated 1975 demand of 13.9 billion pounds and a 1980 demand of 22.2 billion pounds.

5) *Petrochemical Toluene*

Petrochemical demand for toluene is small in comparison to other aromatics. Estimates of 1970 demand range from 1.0[21] to 1.5[23] billion pounds, and forecasts for 1980 range from 1.9[21] to 2.2[23] billion pounds.

A 10% growth rate applied to the base 1969 demand of 0.83 billion pounds forecasts a 1975 demand of 1.4 billion pounds and a 1980 forecast demand of 2.1 billion pounds, which is within the published demand range.

6) *Petrochemical Xylene*

Xylenes, lead by the ortho and para isomers, have exhibited a rapid demand growth. Demands for 1970 are set from 1.8[24] to 2.85[23] billion pounds. All demand growth rates[21,23,24] used for forecasts were approximately 10%.

A 10% growth rate applied to a base 1969 demand of 2.18, which was established for a prior Bonner & Moore study, will provide a calculated 1975 demand of 3.8 billion pounds and a 1980 demand of 6.2 billion pounds, which is within the published demand range.

5.3.4 Assumptions Pertaining to Other Product Demands

Fuel gas, coke and sulfur by-products were assumed to have no minimum or maximum constraints put on them. The model was not committed to maintain a fuel balance, but was a long-range predicted cost of purchasing outside fuel. The refinery fuel gas produced was credited at the same value ($2.93 FOEB). Sulfur recovered from H_2S and the coke produced from the delayed coker were considered as by-products, and therefore were not constrained. Current values were used, e.g., coke $5/ton, sulfur $25/long ton.

5.3.5 Assumptions Pertaining to Raw Material Availability

1) *Crude*

The crude yield and properties of its cuts were determined from composition of the crudes used in models created for the API study (Vol. 1).[3] Therefore, the U.S. model ex-California used the crudes reflected in 8 models; small refiners were deleted from the set. They were composited in the ratios used in the API study, correcting for gasoline to crude and resulting in an "average" crude for the U.S. The California crude was determined the same way, using the two California models from the API study. When establishing a base 1969 case, two additional crudes were allowed into the solution. These two crudes represented composited light and heavy crudes that were in the API base cases, and again the compositing was done in the manner used on the average crude. The sum charge of these two crudes was not allowed to exceed ten percent of the total crude selected in the base 1969 cases. Both models selected ten percent more heavy crude, which was then composited into the average crude so that all subject cases run reflected this new average crude. Comparison to reported average gravities and sulfur contents of U.S. crudes was made and a good verification was found. The volume of crude was allowed to seek an optimum at a price of $3.625/bbl.

2) *Twelve-Pound Natural Gasoline*

The natural gasoline available as raw materials to refineries was fixed around the 1969 level. Statistics for natural gasoline and natural gasoline plus condensate charged to the U.S. refineries for 1968 and 1969 are given below:

	Thousand of Barrels	
	Natural Gasoline	N.G. + Plant Condensate
1968	148,132	186,684
1969	157,492	191,824

The model used in this study does not recognize plant condensate, which includes a significant amount of natural gasoline as a feed. To compensate for this, we set the natural gasoline availability somewhat higher than that reported as such; specifically at 171,200,000 bbls per year. Of this, 158,500,000 was assigned to the U.S. ex-California refineries, and 12,700,000 to California refineries.

3) *Butanes*

The United States Department of the Interior's "Minerals Yearbook" was used to establish a ratio of normal to iso-butane for the U.S. excluding California (PADS 1 thru 4) and for California. The 1969 base cases were allowed to purchase an unlimited amount of butanes at the given ratio. The assumption was made that the availability of butanes would not increase over the next ten years and therefore all subject cases could purchase from zero to the level established in the base cases in the ratio mentioned above.

4) *Ethylene Plant Gas Feeds*

Ethane and propane were allowed to be purchased in the base case for U.S. model to feed the ethylene plant. The level of purchase in the base case was then fixed at the base-case level for all subject cases on the assumption that ethane/propane availability would not increase over the next ten years.

5.4 PROCESS CONSTRUCTION INDUSTRY BASIS

5.4.1 Premises

The process construction industry includes the American process plant contractors, process divisions of larger corporations and those portions of other major American industry sectors that support these contractors. They are identified by their high degree of specialization and by their ability to manage complex, large-scale design and construction projects. Except for a few notable exceptions, these contractors have no component-making facilities. The construction load analyzed in this study includes refining and petrochemical investment. In addition to this type of construction, these contractors are engaged in other large projects such as power stations, port facilities, metallurgical projects, and water systems. Recognizing that, within the scope of this study, it is impossible to measure and evaluate all other work areas where the process construction industry is currently involved, it is assumed that the current capacity in those undefined areas is capable of expanding to meet growth requirements. It should be noted, however, that some of this additional construction work may possibly draw upon the resources required to support petroleum and petrochemical activity, especially in the field labor market. For example, if the current rate of growth continues in utility construction, it will be necessary to evaluate the resulting impact on the field labor market, particularly pipefitters and electricians. It should also be noted that escalation and labor efficiency have been excluded from this study. All data are based upon a constant 1972 dollar value and labor efficiency factor.

The refinery investment, on a per-refinery basis, is supplied for each schedule. The petrochemical investment projected, independent of the refinery schedule, is from published historical performance.

Given the petrochemical requirements and the yearly investment on a per-refinery basis for each schedule, this study phase set out to determine:

1) *The total U.S. refinery investment.*

2) *The total construction load on the process construction industry.*

3) *The maximum growth rate the construction industry can reasonably achieve.*

4) *The feasibility of each schedule, based upon the limits imposed by the foregoing objective.*

5.4.2 Major Industry Sectors Studied

It was necessary to identify major industry sectors and to distribute the investment dollar to each sector. This detailed breakdown was necessary to derive meaningful capacity limits for industry segments in which the lead time (prior to facility start-up) varies considerably. The industry was studied in four major sectors:

1) *Engineering* included process engineering, estimating and scheduling, design, project management, contract supervision and overhead.

2) *Hardware* covered the costs for vessels, columns and exchangers, for piping and valves, for pumps and compressors, and for controls, electrical wiring, dryers, etc.

3) *Field Labor* includes pipefitting, electrical and insulation workers and others.

4) *Fees and Miscellaneous* covered process fees, contract application costs and others.

The following list reflects the historical distribution of all process investment for on-site and off-site facilities. The factors in the foreign column apply to all foreign investment available to the U.S.-based contractors.

	Domestic (US/Canada)	Foreign
U.S. Industry		
Engineering	13%	13%
Materials	50%	10%
Field Labor	20%	5%
Fees & Misc.	17%	15%
Foreign Industry	0%	57%
	100%	100%

5.4.3 Projection Approach

Given the foregoing relationships and the premise conditions, the load on each sector was determined and the percent increase over each prior year was calculated. The percent of increase over the prior year was used as the growth capability factor for each sector.

Base capacity calculations for each of the construction sectors used historical performance of the same process industries evaluated in this study. Growth was projected from this base, analyzing historical trends and the current workload, and could be modified significantly by:

1) Drawing from resources currently being used by industries not included in this study.

2) Having those industries recruit manpower that has historically worked in the process industries.

From total projections, the expenditures for petrochemicals, foreign operations, refinery replacement and obsolescence, etc., were subtracted. The remaining capacity was assumed available for the various lead-removal programs. It should be noted that any other major changes or environmental regulation imposed upon the process industry would have to utilize these same resources, and thus could delay a concerted lead-removal program.

5.4.4 Project Cycle

The model results yielded yearly process construction investment required to meet projected market demands. This projected investment was then distributed in time to show when the various construction activities must occur.

Most projects of the type included in this study require from two to four years for completion. A construction period of 30 months was used in this analysis (see Figure 5-2). This includes 6 months for the start-up year, and two preceding years. As can be noted from the following table, 96% of the engineering is completed prior to the start-up year and is fairly evenly distributed between the prior two years, and tends to smooth the sector requirements as related to the overall investment. The data for this table are from engineering and construction sources.

	Percent Performance by Year		
Construction Sector	Start-Up year	Start-Up year -1	Start-Up year -2
Engineering	4	52	44
Materials	2	64	34
Field Labor	28	71	1
Fees & Misc.	14	70	16

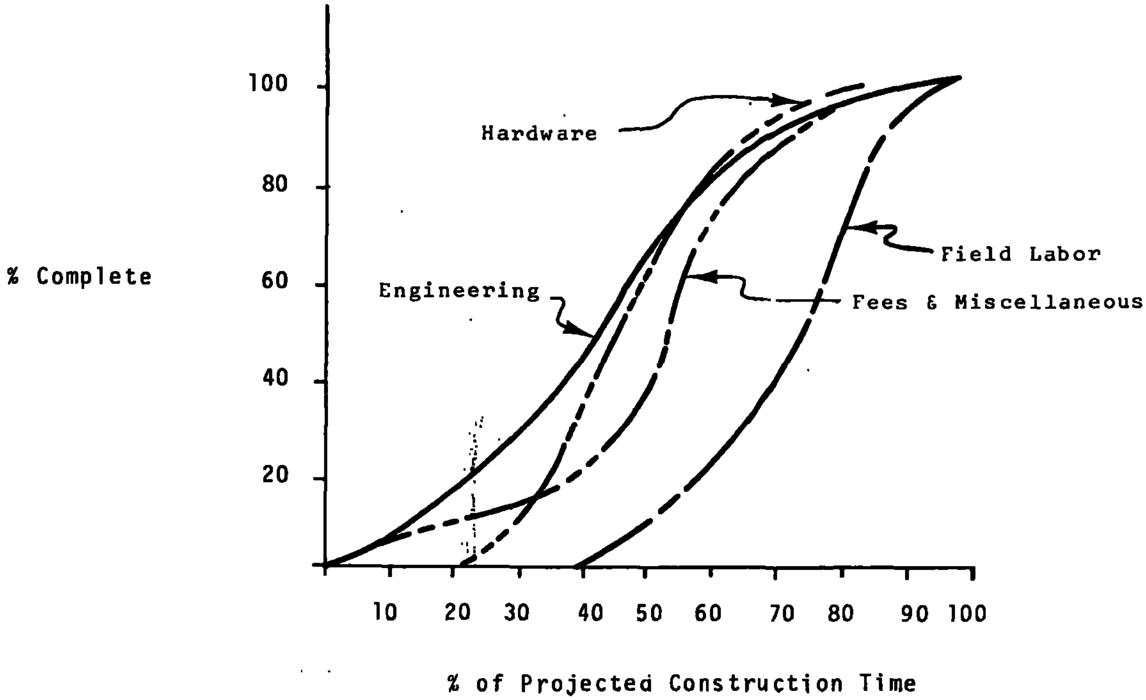


Figure 5-2. Investment Distribution for Process Construction Sectors

5.4.5 Historical Investment

The plot shown in Figure 5-3 illustrates historical investment made by the U.S. petroleum industry in refining and petrochemicals. The corresponding data for chemical companies and their petrochemical investment are much more difficult to define, especially that portion which affects the process construction industry. Another factor which further complicates measuring the chemical companies' impact on the process construction industry is that, during the past several years, these companies have been changing from a mode of operation in which they designed their own plants and procured their materials directly from component makers to today's operation in which more than 50% of their major new plants are engineered, procured, and constructed by process contractors. This is further reflected in the comment from one major contractor who stated: "In the last few years we have moved from 100% refining to 100% chemical business." This shift by the chemical companies will continue to change the composition of the contractors' work load and is reflected in the base construction level. Therefore, the petrochemical investment which was used as a base was taken from data reported by the process contractors.

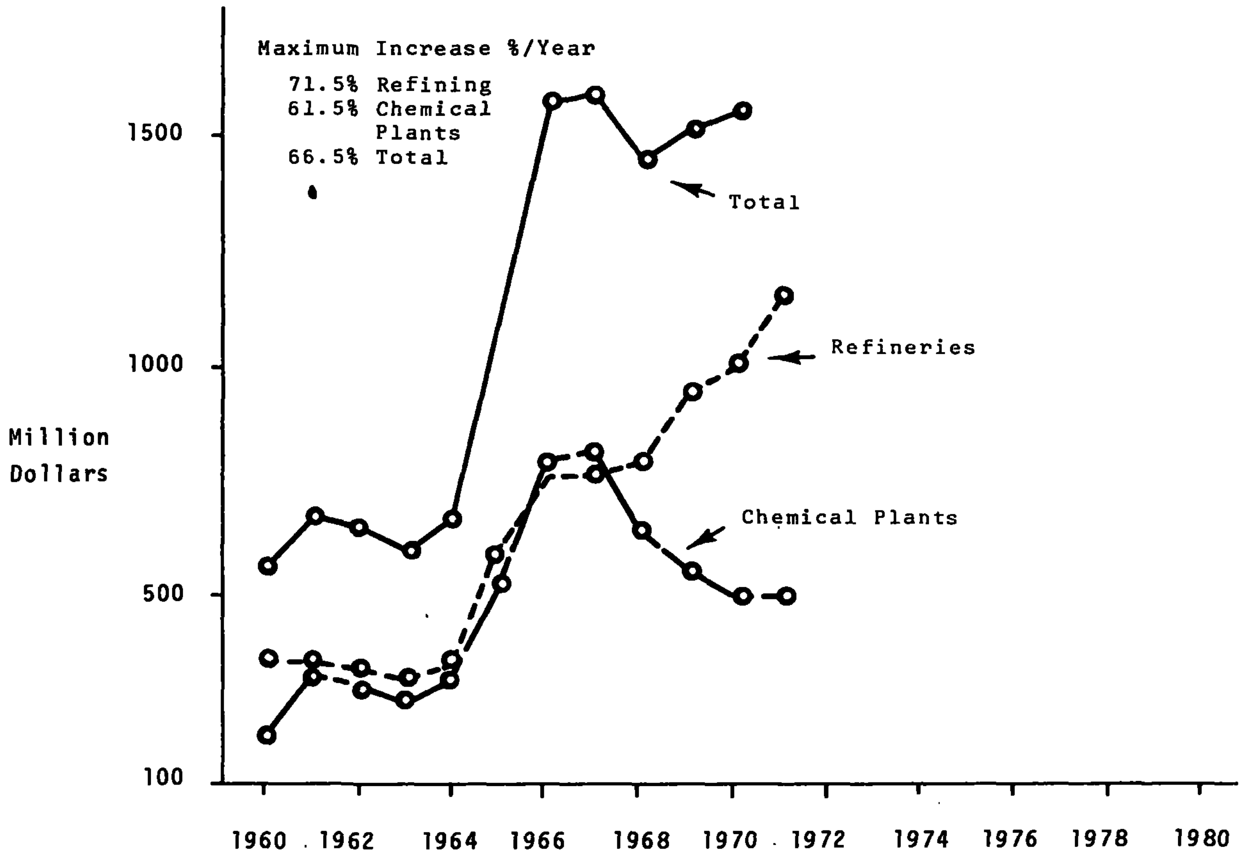


Figure 5-3. Historical Investment[27]

5.4.6 Projected Maximum Growth Rates by Sector

1) *Engineering*

The ability of the process industry contractor to handle a substantial increase in work will be highly dependent upon the timing and the rate of growth. In mid-1970, the engineering staffs of the process construction industry reached an all-time high. Since that time this force has been decreasing. Currently, much of the design engineering force that has been terminated is believed not to have found permanent employment in other fields and can possibly be attracted back to the process construction industry. It should also be noted that the retained staff represents project management and other senior level personnel who are capable of handling a much larger staff without degrading efficiency.

Based on the above and on direct input from the construction and petroleum companies as reported to the EPA study team, the following maximum growth was determined.

1971 (4th qtr)	1972	1973	1974	1975 - 1980
10%	25%	20%	15%	12%/Yr

In order to calculate the percent increase in 1971, a 1970 base had to be established. This was accomplished by calculating 1969 engineering required to support 1969, 1970, and projected 1971 investment, using the relationships described earlier (5.4.9 and 5.4.10), and assuming that the average 1970 engineering level was the same as 1969.

2) *Hardware*

The manufacturing segment of this industry, as a whole, is operating at 60% to 80% of current capacity. Backlog is quite small and a sharp decline is being projected for the last quarter of 1971. Much of the total work done by these companies is external to the construction being examined in this study and their ability to react to a major expansion is somewhat dependent upon other construction levels. Another factor to be considered is the lead time that they have after the engineering has been initiated. The maximum growth rates used in the analysis are:

1971 - 1972	1973	1974	1975 - 1980
35%	20%	20%	15%

3) *Field Labor*

The lead time for obtaining a field labor force is approximately one year (see Figure 5-2). It is therefore concluded that this sector will not be a limiting factor. In the recent past, however, considerable difficulty has resulted from reduced efficiency when an abnormally high demand has been placed upon a local labor force. With this in mind, and after perusing Bureau of Labor statistics, the following maximum annual rates for field labor growth were established:

1971 - 1974	1975 - 1980
20%/Yr	15%/Yr

5.4.7 Refinery Obsolescence and Replacement Costs

The investment required for obsolescence and replacement was set at $284 million for refining in 1969. This amount was increased each year by 1.89%[28] of the previous year's added investment. The base number was developed by using the 1969 refining capacity, as defined by this study, the obsolescence rate of 1.89%, and the investment cost of $1,300 per barrel per day.

5.4.8 Petrochemical and Foreign Refining Use of Construction Industry

The rate applied to petrochemical growth is 12% per year for the first four years and 10% per year thereafter. The 2% decrease after the first four years reflects completion of environmental and other miscellaneous projects that are already being planned by the industry. Foreign and residual desulfurization work is based upon historical performance in the foreign market and upon desulfurization requirements as reported by construction industry sources.

5.4.9 Combined Process Construction Industry Growth Projection

Table 49 shows the combined, maximum process-industry construction capacity in dollars-by-year. Using the maximum growth rates per industry sector and the average project cycle, maximum annual capacity of the total process construction industry was derived. The petrochemical and foreign refining demands upon this capacity were derived from the projections of historical data. These projections were subtracted from the total annual process construction capacity, leaving U.S. refining capacity projections shown in Table 49. (The Canadian refining capacity is 11% of the U.S. refining capacity.) U.S. refining construction capacity is that available for replacing obsolescent facilities, residual desulfurization, refinery expansion and lead-removal programs.

At the present time, much of the refining industry is delaying announcements of future building programs until a positive direction has been established for lead removal. The impact on the process construction industry is evident; contractors are reducing engineering staffs, and suppliers are predicting definite business reductions in late 1971. The current contractor backlog is very low relative to traditional levels. These observations are taken into consideration in the projected growth rates for the various construction sectors. However, this low construction backlog also implies that other programs are possibly being delayed for various reasons. If this is a valid assumption, and if other delayed projects are initiated during the period 1971 to 1980, it should be reemphasized that these programs would be competing for the resources allocated in this study to the lead-removal program.

TABLE 49

COMBINED PROCESS CONSTRUCTION INDUSTRY MAXIMUM GROWTH PROJECTION

MM$/YEAR

	PETROCHEMICAL			REFINING				TOTAL		
	FOREIGN	US/CANADA	TOTAL	FOREIGN	CANADA	US	TOTAL	FOREIGN	US/CANADA	TOTAL
1970	100	1,200	1,300	105	115	1,050	1,270	205	2,365	2,570
1971	110	1,330	1,440	125	127	1,158	1,411	235	2,616	2,851
1972	120	1,500	1,620	140	70	635	845	260	2,205	2,465
1973	135	1,680	1,815	150	152	1,386	1,688	285	3,218	3,503
1974	150	1,880	2,030	160	178	1,615	1,953	310	3,673	3,983
1975	165	2,020	2,185	170	236	2,147	2,553	335	4,403	4,738
1976	185	2,220	2,405	180	265	2,443	2,888	365	4,898	5,263
1977	205	2,440	2,645	185	305	2,771	3,261	390	5,516	5,906
1978	230	2,690	2,920	190	345	3,137	3,672	420	6,172	6,592
1979	250	2,960	3,210	195	394	3,585	4,174	445	6,939	7,384
1980	280	3,250	3,530	200	449	4,085	4,735	480	7,785	8,265
1981	310	3,580	3,890	205	513	4,660	5,378	515	8,753	9,268
1982	345	3,930	4,275	210	587	5,334	6,131	555	9,850	10,405
TOTALS	2,565	30,680	33,265	2,215	3,737	33,976	39,929	4,800	68,394	73,194

5.4.10 Extrapolation of Investment per Refinery to Industry Investment Requirements[29]

The model results indicate the investment required for an average sized refinery in the U.S. (ex California) and California. The investments are extrapolated to represent total U.S. investment by the following formulas.

1) *U.S. (ex California) Investment*

I = investment/98.5MB per day refinery

98.5 - average size of all refineries greater than 35MB/D

.7 (see Figure 4-1†)

91 = number of refineries greater than 35MB/D

16.5 = average size of all refineries less than 35MB/D

68 = number of refineries less than 35MB/D

$$\text{Total Investment} = 91(I)+68(I)\left(\frac{16.5}{98.5}\right)^{.7}$$

$$= 91(I)+19.45(I) = 110.45(I)$$

2) *California Investment*

I = investment/104 MB per day refinery

104 = average size of all refineries greater than 35MB/D

22.87 = average size of all refineries less than 35MB/D

13 = number of refineries greater than 35MB/D

.7 = (see paragraph 5.5.1)

6 = number of refineries less than 35MB/D

$$\text{Total Investment} = 13(I)+6(I)\left(\frac{22.87}{104}\right)^{.7}$$

$$= 131.0(I)+2.08(I) = 15.08(I)$$

---

†Investment relationship employed customary form $\frac{I1}{I2} = \left(\frac{C1}{C2}\right)^{K}$

APPENDIX A

LEAD REMOVAL SCHEDULES

Schedules reflect recommendations recently made by the Commerce Technical Advisory Board (CTAB), i.e., general availability of an unleaded grade of gasoline by July 1, 1974, and nation-wide availability of a low-leaded fuel no later than the end of calendar year 1972.

APPENDIX A

LEAD REMOVAL SCHEDULES

(ALLOWABLE LEAD LEVELS GRAMS TEL/GALLON)

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
SCHEDULE A (3 Pump System)										
93 RON	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
94 RON	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
100 RON	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
SCHEDULE B (3 Pump System)										
93 RON	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
94 RON	3.0	2.0	1.5	1.0	0.5	0.5	0.5	0.5	0.5	0.5
100 RON	3.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
SCHEDULE C (3 Pump System)										
93 RON	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
94 RON	3.0	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
100 RON	3.0	2.0	1.5	1.0	0.5	0.5	0.5	0.5	0.5	0.5
SCHEDULE D (3 Pump System)										
93 RON	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
94 RON	3.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
100 RON	3.0	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
SCHEDULE E (3 Pump System)										
93 RON	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
94 RON	3.0	2.0	2.0	2.0	2.0	0.0	0.0	0.0	0.0	0.0
100 RON	3.0	2.0	2.0	2.0	2.0	0.0	0.0	0.0	0.0	0.0
SCHEDULE F (3 Pump System)										
93 RON	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
94 RON	3.0	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
100 RON	3.0	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
SCHEDULE G (2 Pump System)										
94 RON	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
100 RON	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
SCHEDULE H (2 Pump System)										
94 RON	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
100 RON	3.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0

(ALLOWABLE LEAD LEVELS GRAMS TEL/GALLON)

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
SCHEDULE I (2 Pump System										
94 RON	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
100 RON	3.0	2.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
SCHEDULE J (2 Pump System)										
94 RON	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
100 RON	3.0	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
SCHEDULE K (2 Pump System)										
94 RON	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
100 RON	3.0	2.0	2.0	2.0	2.0	0.0	0.0	0.0	0.0	0.0
SCHEDULE L (3 Pump System)										
93 RON	MIN	MIN	MIN	0.0	0.0	0.0	0.0	0.0	0.0	0.0
94 RON	MIN	MIN	MIN	MIN	MIN	MIN	MIN	MIN	MIN	MIN
100 RON	MIN	MIN	MIN	MIN	MIN	MIN	MIN	MIN	MIN	MIN
SCHEDULE M (2 Pump System)										
94 RON	MIN	MIN	MIN	0.0	0.0	0.0	0.0	0.0	0.0	0.0
100 RON	MIN	MIN	MIN	MIN	MIN	MIN	MIN	MIN	MIN	MIN

APPENDIX B

SAMPLE MODEL OUTPUT REPORTS

APPENDIX B

SAMPLE MODEL OUTPUT REPORTS

Model solutions were generated as computer printed reports for each schedule studied. These reports are briefly described here with example reports of Schedule A, year 1980. One complete set of reports for all schedules and years studied has been supplied to EPA.

The reports can be described in six categories:

- Build and Expand Investment Summary.
- Material and Economic Balances.
- Blending Summaries.
- Detailed Stream Production/Consumption Reports.
- Utility Summary.
- Overall Economic Summary.

1) *Build and Expand Investment Summary*

This report includes a row for each active new facility variable, defining the new stream day capacity constructed, the cost coefficient on the new facility variable, the investment (broken out as plant, off-site, catalyst, and royalty), the combined expenses (maintenance, insurance/taxes/overhead, variable costs and fixed costs) as a single item, and the capital recovery requirements for each unit.

2) *Material and Economic Balances*

This group of reports presents weight and volume balances. The first presents purchases and sales of all weight basis stocks, their production, the unit price, and the total dollars per calendar day. In addition, any net production or consumption of weight basis stocks through volume-to-weight or weight-to-volume conversions is reported, permitting verification of a complete weight balance around the refinery.

The next report presents similar information for those stocks being purchased or sold on a volume basis. Note that in order to secure a proper material balance closure, it is desirable to show volumetric loss as a sales product, at zero price. All of the information in these two reports is derived directly from the LP solution.

3) *Blending Summaries*

This series of reports summarizes the recipe and specification blended-product formulations. Recipe blended products are reported first, with volume basis blends following the weight basis blends. For each such product produced, the composition is displayed both in weight or volume units, and as a percentage formulation.

In addition to the display of formulations, the specification blend summaries include a recap of the status of all specifications. For each specification on the blend being summarized, the minimum and/or maximum and the actual final quality is displayed. Although the blend formulations for both recipe and specification blends are developed entirely from LP solution information, the specification summary derives some of its data from the original input information.

4) *Stream Production/Consumption Reports*

These reports include a Unit Operations Recap and an Operations Summary, presented separately for weight basis and volume basis stocks. The weight basis Unit Operations Recap includes a row for each stock referenced on a weight basis in any part of the model (purchases, sales, blending, unit operations, or weight/volume conversions). It includes a column for every unit operation, arranged 9 units to the page. The report displays the total production (as negative numbers) or consumption (as positive numbers) of each stock by each unit. The results are totaled by columns, giving a quick and convenient verification of material balance closure around each unit. Following the weight basis Unit Operations Recap, the weight basis Operations Summary is printed. The row-wise structure of this report is identical to that of the weight basis Unit Operations Recap. It includes columns for purchases, unit operations, recipe blending, sales, and weight/volume conversions. The entries in the unit operations column are the row totals from the weight basis Unit Operations Recap, representing the new production or consumption of the stock in question by all of the unit operation submodels combined. The other columns contain appropriate entries, following the same sign convention as the Unit Operations Recap. Row totals are calculated and displayed, and a total of zero verifies proper material balance closure and accountability for all production and consumption of the stock in question. A final column displays the reduced costs or incremental value for all of the stocks. Since this report includes both the 3 character tags and the full 18 character labels for all of the weight basis stocks, it serves as a convenient cross-reference index of stock labels and tags.

The weight basis Unit Operations Recap and Operations Summary are followed by a similar pair of reports for volume basis stocks and units. The volume basis Operations Summary includes a column for specification blends in addition to the same columns that are included in the weight basis Operations Summary. If a particular unit has both weight and volume basis stocks represented, it is included in both reports.

This group of reports gives a comprehensive picture of the patterns of production and consumption of all raw materials, intermediate stocks, and finished products in the refinery model.

5) *Utility Summary*

The utility summary report presents the net production or consumption of each utility by each unit operation. Each utility occupies a column of the table, and a row is assigned to each unit operation. The net utility cost for each unit, and the unit cost and total cost for each utility are reported. If there is a net production (rather than consumption) of a particular utility, its cost is reported as zero.

6) *Overall Economic Summary*

The overall economic summary is a consolidation and recap of cost information presented in the earlier reports. It includes the net sales and purchase figures from the weight and volume basis feed and product balances, the total utilities from the utility summary, TEL purchases, and the expenses associated with installation and operation of the new equipment (maintenance, insurance/taxes/overhead, fixed and variable operating costs, as well as the capital recovery requirement).

USA, EX CALIF, YEAR 1980, SCHEDULE A   PEAK PERIOD RUN   PRIOR YEAR IS 1970   1 1 1

BUILD AND EXPAND INVESTMENT SUMMARY

PROCESS	SIZE/SD	$/U-SIZE	INVESTMENT M$ PLANT	OFFSITE	CATALYST	ROYALTY	TOTAL	EXPENSES $/CD	CAP REC $/CD
BUILD CRUDE UNIT	56,912	-0.147	5,701	5,359			11,059	2,424	5,511
BUILD VACUUM UNIT	26,295	-0.128	3,303	1,156			4,459	977	2,222
BUILD DELAYED COKER	10,865	-0.585	6,090	2,131			8,221	1,802	4,097
BUILD VISBREAKER	3,177	-0.161	517	145			661	145	330
BUILD VAC UNIT TRTD BTMS	1,005	-0.186	189	53			242	53	120
BUILD HYDROCRACKER	5,882	-0.854	4,980	1,394	245	496	7,116	1,397	3,310
BUILD ALKYLATION	3,447	-0.816	2,813	675	227	318	4,033	764	1,836
BUILD KERO GAS OIL H2 TR	11,193	-0.154	1,864	373			2,237	490	1,115
BUILD NAPHTHA H2 TRTR	8,924	-0.094	775	217	35		1,026	217	500
BUILD PYROL GASOL TRTR	4,603	-0.261	1,106	310	45	166	1,626	310	743
BUILD CAT REFORMER	15,411	-0.422	5,866	1,642	919	752	9,179	1,646	4,042
BUILD AROM SEPARATION	2,535	-0.459	1,149	138	89	200	1,576	282	693
BUILD BENZENE TOWER	10,121	-0.153	1,794	215			2,010	440	1,002
BUILD TOLUENE TOWER	5,038	-0.164	1,717	206			1,923	422	958
BUILD XYLENE TOWER	3,478	-0.179	719	86			805	176	401
BUILD HYDRODEALKYLATION	665	-0.764	544	109	17		670	143	328
BUILD C4 ISOMERIZATION	379	-0.316	125	30			155	34	77
BUILD DEPENTANIZER	678	-0.019	15	2			16	4	8
BUILD H2 PURIFICATION	5	-0.062	0	0			0	0	0
BUILD MEROX	3,835	-0.103	430	82			511	112	255
BUILD SULFUR PLANT	19	-5.020	118	23			141	31	70
BUILD BOILER PLANT	2,679	-0.308	763	305			1,068	234	532
BUILD COOLING TOWER	43,686	-0.013	631	208			839	184	418
SUB-TOTAL UNITS			41,207	14,858	1,576	1,933	59,574	12,288	28,571

USA, EX CALIF, YEAR 1980, SCHEDULE A   PEAK PERIOD RUN   PRIOR YEAR IS 1970   1 2 1

MATERIAL AND ECONOMIC BALANCE - WEIGHT BASIS

PRODUCTS	$/MLB	MLB/CD	$/CD	MMLB/YR
COKE @ $5.00/TON	2.500	1,578	3,945	576
SULFUR @ $25.00/LT	11.360	57	648	21
ETHYLENE	35.000	1,160	40,605	423
PROPANE UNSATS	37.000	586	21,696	214
BUTADIENE	75.000	134	10,054	49
BENZENE	33.000	560	18,481	204
TOLUENE	29.000	55	1,583	20
XYLENES	31.000	128	3,969	47
WEIGHT LOSS		457		167
WT TO VOL CONV		2,626		
		-------	------	
TOTAL PRODUCTION		7,341	100,980	

FEEDS	$/MLB	MLB/CD	$/CD	MMLB/YR
ETHANE	-12.900	211	-2,717	77
VOL TO WT CONV		7,131		
		-------	------	
TOTAL FEEDSTOCKS		7,341	-2,717	

PRODUCTION MARGIN			98,264	

USA, EX CALIF, YEAR 1980, SCHEDULE A   PEAK PERIOD RUN   PRIOR YEAR IS 1970   1 3 1

MATERIAL AND ECONOMIC BALANCE - VOLUME BASIS

PRODUCTS	$/BBL	BBL/CD	$/CD	MBBL/YR
FUEL GAS	2.930	6,906	20,236	2,521
LPG FOR FUEL	2.730	804	2,196	294
93 RON MOTOR GASO	4.620	47,180	217,969	17,221
94 RON MOTOR GASO	4.630	19,307	89,392	7,047
100 RON MOTOR GASO	5.670	1,837	10,417	671
SPECIAL NAPHTHAS	4.200	3,689	15,493	1,346
JP-4 NAPHTHA JET	4.200	1,588	6,671	580
KEROSINE & JP-5	4.410	18,444	81,340	6,732
DISTILLATE FUELS	3.780	34,660	131,015	12,651
RESIDUAL FUEL OIL	2.730	9,644	26,328	3,520
VOLUMETRIC LOSS		-7,786		-2,842
VOL TO WT CONV		22,977		
		-------	------	
TOTAL PRODUCTION		159,251	601,056	
FEEDS				
NORMAL BUTANE	-3.150	1,952	-6,149	712
ISO-BUTANE	-3.260	1,405	-4,582	513
NATURAL GASOLINE	-3.470	4,060	-14,088	1,482
CRUDE	-3.625	142,401	-516,203	51,976
WT TO VOL CONV		9,433		
		-------	------	
TOTAL FEEDSTOCKS		159,252	-541,022	

PRODUCTION MARGIN			60,034	

USA, EX CALIF, YEAR 1980, SCHEDULE A   PEAK PERIOD RUN   PRIOR YEAR IS 1970   1 4 1

WEIGHT BASIS RECIPE BLENDS

PROPANE UNSATS

COMPONENT		MLB/CD	PERCENT COMPONENT
C3U	PROPYLENE	586	100.0
	TOTAL	586	100.0

VOLUME BASIS RECIPE BLENDS

LPG FOR FUEL

	COMPONENT	BBL/CD	PERCENT COMPONENT
C3S	PROPANE	760	94.5
NC4	NORMAL BUTANE	44	5.5
	TOTAL	804	100.0

* * * * * * *

SPECIAL NAPHTHAS

	COMPONENT	BBL/CD	PERCENT COMPONENT
HSM	MEROX TRTD HSR	1,107	30.0
KHR	H2 TRTD KEROSENE	2,582	70.0
	TOTAL	3,689	100.0

VOLUME BASIS RECIPE BLENDS

JP-4 NAPHTHA JET

COMPONENT		BBL/CD	PERCENT COMPONENT
LLM	C5-145 CRD.NAP.	175	11.0
LSM	145-200 CRD.NAP.	159	10.0
MSM	200-330 CRD.NAP.	461	29.0
HSM	MEROX TRTD HSR	191	12.0
KHR	H2 TRTD KEROSENE	604	38.0
TOTAL		1,588	100.0

VOLUME BASIS SPEC BLENDS

93 RON MOTOR GASO

VOLUME AND COMPOSITION REPORT

	COMPONENT TO BLEND	VOLUME BBL/CD	PERCENTAGE COMPOSITION
NC4	NORMAL BUTANE	2,532	5.4
IC5	ISO-PENTANE	72	0.2
C5M	THERMAL PENTANES	471	1.0
LLM	C5-145 CHD.NAP.	1,248	2.6
FCM	C5-430 CAT GASO.	3,144	6.7
LCM	C5-250 CAT GASO	1,840	3.9
LA3	PROPYLENE ALKY.	2,032	4.3
LA4	BUTYLENE ALKYLATE	5,703	12.1
LHC	C5-C6 HYDROCRAKATE	3,257	6.9
NAT	NATURAL GASOLINE	4,060	8.6
SCN	H2 TRT PYROL.GASO.	4,248	9.0
TOL	TOLUENE	591	1.3
XYL	XYLENE	1,680	3.6
S95	95 SEV FULL REFMT	12,200	25.9
HAR	HVY AROMATICS	2,201	4.7
XYH	XYLENE TOWER FEED	1,900	4.0
	TOTAL	47,179	100.0

QUALITY REPORT

	SPECIFICATION	MINIMUM	QUALITY	MAXIMUM
TEL	TEL			
RON	RESEARCH OCTANE	93.0	93.0	
MON	MOTOR OCTANE	85.0	85.0	
RVP	REID VAPOR PRESS		10.1	10.1
160	PCT OFF AT 160	18.0	33.6	35.0
210	PCT OFF AT 210	39.0	49.3	57.0
230	PCT OFF AT 230	49.0	58.8	
330	PCT OFF AT 330	84.0	92.7	96.0

USA, EX CALIF, YEAR 1980, SCHEDULE A   PEAK PERIOD RUN   PRIOR YEAR IS 1970   1 8 1

VOLUME BASIS SPEC BLENDS

94 RON MOTOR GASO

VOLUME AND COMPOSITION REPORT

	COMPONENT TO BLEND	VOLUME BBL/CD	PERCENTAGE COMPOSITION
NC4	NORMAL BUTANE	927	4.8
LLM	C5-145 CRD.NAP.	3,401	17.6
LSM	145-200 CRD.NAP.	745	3.9
VBM	C5-400 VISB.GASO.	517	2.7
FCM	C5-430 CAT GASO.	9,259	48.0
HCM	250-410 CAT GASO	2,195	11.4
LRF	C5-IC6 RAFFINATE	494	2.6
HRF	C6-FBP RAFFINATE	1,769	9.2
	TOTAL	19,307	100.0

QUALITY REPORT

	SPECIFICATION	MINIMUM	QUALITY	MAXIMUM
TEL	TEL		2.771	
RON	RESEARCH OCTANE	94.0	94.0	
MON	MOTOR OCTANE	86.0	86.0	
RVP	REID VAPOR PRESS		10.1	10.1
160	PCT OFF AT 160	18.0	35.0	35.0
210	PCT OFF AT 210	39.0	57.0	57.0
230	PCT OFF AT 230	49.0	64.3	
330	PCT OFF AT 330	84.0	88.4	96.0

USA, EX CALIF, YEAR 1980, SCHEDULE A   PEAK PERIOD RUN   PRIOR YEAR IS 1970   1 9 1

VOLUME BASIS SPEC BLENDS

100 RON MOTOR GASO

VOLUME AND COMPOSITION REPORT

	COMPONENT TO BLEND	VOLUME BBL/CD	PERCENTAGE COMPOSITION
NC4	NORMAL BUTANE	81	4.4
LLN	C5-145 CRD.NAP.	252	13.7
FCN	C5-430 CAT GASO.	733	39.9
LA4	BUTYLENE ALKYLATE	624	34.0
TOL	TOLUENE	9	0.5
S90	90 SEV FULL RFMT	138	7.5
	TOTAL	1,837	100.0

QUALITY REPORT

	SPECIFICATION	MINIMUM	QUALITY	MAXIMUM
TEL	TEL		3.000	
RON	RESEARCH OCTANE	100.0	100.0	
MON	MOTOR OCTANE	92.0	92.0	
RVP	REID VAPOR PRESS		10.3	10.3
160	PCT OFF AT 160	18.0	33.0	33.0
210	PCT OFF AT 210	39.0	54.0	54.0
230	PCT OFF AT 230	49.0	67.7	
330	PCT OFF AT 330	84.0	92.5	96.0

VOLUME BASIS SPEC BLENDS

KEROSINE & JP-5

VOLUME AND COMPOSITION REPORT

	COMPONENT TO BLEND	VOLUME BBL/CD	PERCENTAGE COMPOSITION
HSM	MEROX TRTD HSR	4,095	22.2
KHR	H2 TRTD KEROSENE	13,577	73.6
HVA	HEAVY ALKYLATE	773	4.2
	TOTAL	18,444	100.0

QUALITY REPORT

	SPECIFICATION	MINIMUM	QUALITY	MAXIMUM
FLS	FLASH INDEX		274.4	280.0
350	PCT OFF AT 350		8.2	10.0
400	PCT OFF AT 400	6.0	37.9	

USA, EX CALIF, YEAR 1980, SCHEDULE A   PEAK PERIOD RUN   PRIOR YEAR IS 1970   1 11 1

VOLUME BASIS SPEC BLENDS

DISTILLATE FUELS

VOLUME AND COMPOSITION REPORT

	COMPONENT TO BLEND	VOLUME BBL/CD	PERCENTAGE COMPOSITION
HSM	MEROX TRTD HSR	1,040	3.0
SHV	TRTD HVY VAC G.O.	1,805	5.2
SCY	TRTD LT CYCLE OIL	3,098	8.9
HLG	650-750 G.O.FM HOL	141	0.4
HLB	750-930 LT.CTK HOL	485	1.4
HCD	HYDROCRACK DIST.	363	1.0
KER	375-550 KEROSENE	8,442	24.4
LVO	LT.VIRGIN GAS OIL	4,073	11.8
LCO	LT CYCLE OIL	2,347	6.8
KGO	COKER GAS OIL	9,799	28.3
VBO	VISBREAKER GAS OIL	3,067	8.8
	TOTAL	34,660	100.0

QUALITY REPORT

SPECIFICATION	MINIMUM	QUALITY	MAXIMUM
FLS FLASH INDEX		153.8	170.0

USA, EX CALIF, YEAR 1980, SCHEDULE A   PEAK PERIOD RUN   PRIOR YEAR IS 1970   1 12 1

VOLUME BASIS SPEC BLENDS

RESIDUAL FUEL OIL

VOLUME AND COMPOSITION REPORT

	COMPONENT TO BLEND	VOLUME BBL/CD	PERCENTAGE COMPOSITION
VBR	VIS BRKR RESID.	3,738	38.8
STR	STM CRACK RESID.	1,716	17.8
SLP	CAT SLURRY	2,146	22.3
KER	375-550 KEROSENE	361	3.7
HBF	650+HYDRFIN BT RSD	1,373	14.2
HHB	930+ ETHS FU HBL	309	3.2
	TOTAL	9,644	100.0

QUALITY REPORT

	SPECIFICATION	MINIMUM	QUALITY	MAXIMUM
FLS	FLASH INDEX		28.6	130.0
VBN	INDEX OF VISC		12.8	12.8
SUL	PERCENT SULFUR		2.000	2.000

RGH-015

UNIT OPERATIONS RECAP - WEIGHT BASIS - MLB/CD

	FHSL	FHKT	FHCK	FCCU	FHG8	FH2F	FSCK	FH2P
	H-SIL UNIT	H.S.HYDROF	HYDROCRACK	CAT CRACK	H_2 TRT G.O	NAP. HDS	OLEFINS	H_2 PURIFCT
ETHANE							251	
PROPANE							294	
HYDROGEN SULFIDE		-15	-16	-3	-20	-4		
WEIGHT LOSS		15	16	3	20	4	-469	-46
ETHANE, INTRNL REC							0	
PROPANE.FM SCK								
ISO-BUTANE								
NORMAL BUTANE								
NC5-145 STR.RUN								
C5 THRU C6 VIRG NP								
145-200 STR.RUN								
200-330 STR.RUN								
330-400 STR.RUN								
NAPH. FEEDS								
LT HYDROCRACKATE								
NORMAL PENTANE								
LT. RAFFINATE								
HVY. RAFFINATE								
S.R. KERO 350-450								
LT.VIRGIN GAS OIL							3,898	
LT.VACUUM GAS OIL							600	
HYDROCRACKER KERO								
HYDROCRACKER 550+								
STM CRK H2,MLBS							-46	46
ETHYLENE							-1,160	
PROPYLENE							-609	
BUTADIENE							-464	
PYROLYSIS GASOLINE							-1,242	
STM CRK G.O400-650							-525	
STM CRK TAR 650.							-528	
SULFUR @ $25.00/LT								
COKE @ $5.00/TON								
PROPANE UNSATS								
BENZENE								
TOLUENE								
XYLENES								
TOTALS							0	

Bonner & Moore Associates, Inc.

RGH-015

UNIT OPERATIONS RECAP - WEIGHT BASIS - MLB/CD

	VSUL SULFUR PLT
ETHANE	
PROPANE	
HYDROGEN SULFIDE	58
WEIGHT LOSS	-1
ETHANE,INTRNL REC	
PROPANE.FM SCK	
ISO-BUTANE	
NORMAL BUTANE	
NC5-145 STR.RUN	
C5 THRU C6 VIRG NP	
145-200 STR.RUN	
200-330 STR.RUN	
330-400 STR.RUN	
NAPH. FEEDS	
LT HYDROCRACKATE	
NORMAL PENTANE	
LT. RAFFINATE	
HVY. RAFFINATE	
S.R. KERO 350-450	
LT.VIRGIN GAS OIL	
LT.VACUUM GAS OIL	
HYDROCRACKER KERO	
HYDROCRACKER 550+	
STM CRK H2,MLBS	
ETHYLENE	
PROPYLENE	
BUTADIENE	
PYROLYSIS GASOLINE	
STM CRK G.O400-650	
STM CRK TAR 650.	
SULFUR @ $25.00/LT	-57
COKE @ $5.00/TON	
PROPANE UNSATS	
BENZENE	
TOLUENE	
XYLENES	
TOTALS	-0

Bonner & Moore Associates, Inc.

OPERATIONS SUMMARY - WEIGHT BASIS - MLB/CD

	PURCHASES	UNITS	REC BLN		SALES	V/W CONV	TOTALS		INCR VAL
ETHANE	-211	251				-40	-0	C2S	15.864
PROPANE		294				-294		C3S	11.425
HYDROGEN SULFIDE		0					0	H2S	8.189
WEIGHT LOSS		-457			457		0	LSS	
ETHANE,INTRNL REC		0					0	ETH	15.864
PROPANE.FM SCK								PRO	11.425
ISO-BUTANE								IC4	9.829
NORMAL BUTANE								NC4	13.024
NC5-145 STR.RUN								LLR	12.507
C5 THRU C6 VIRG NP								LNP	12.507
145-200 STR.RUN								LSR	16.377
200-330 STR.RUN								MSR	15.801
330-400 STR.RUN								HSR	15.254
NAPH. FEEDS								NAP	13.383
LT HYDROCRACKATE								LHC	12.507
NORMAL PENTANE								NC5	12.507
LT. RAFFINATE								LRF	21.757
HVY. RAFFINATE								HRF	17.086
S.R. KERO 350-450								KER	14.189
LT.VIRGIN GAS OIL		3,898				-3,898	0	LVO	13.740
LT.VACUUM GAS OIL		600				-600	-0	LGO	13.640
HYDROCRACKER KERO								KHR	15.036
HYDROCRACKER 550+								HCD	14.252
STM CRK H2,MLBS		0					0	HYL	0.023
ETHYLENE		-1,160			1,160		0	C2U	18.581
PROPYLENE		-609	586			23		C3U	9.065
BUTADIENE		-464			134	330	0	SC4	13.080
PYROLYSIS GASOLINE		-1,242				1,242	0	PYR	18.619
STM CRK G.O.400-650		-525				525	0	SGO	14.026
STM CRK TAR 650+		-528				528	0	STR	10.307
SULFUR @ $28.00/LT		-57			57			SUS	11.360
COKE @ $5.00/TON					1,578	-1,578	0	COK	2.500
PROPANE UNSATS			-586		586			PRU	9.065
BENZENE					560	-560		BNZ	29.936
TOLUENE					55	-55		TOL	23.559
XYLENES					128	-128	0	XYL	22.121
TOTALS	-211	0			4,715	-4,505			

USA, EX CALIF, YEAR 1980, SCHEDULE A   PEAK PERIOD RUN   PRIOR YEAR IS 1970   1 16 I

UNIT OPERATIONS RECAP - VOLUME BASIS - BBL/CD

	FCRD	FVAC	FCKR	FTHM	FVBR	FHOL	FHKT	FVHK
	CRUDE DIST	VACUUM	COKER DELD	THERMAL CK	VISBREAKER	H-OIL UNIT	H.O.HYDROF	VAC HYDR B
ETHYLENE								
NORMAL BUTANE	-251		-213		-38			
ISO-BUTANE	-219		-71		-15			
NATURAL GASOLINE								
CRUDE	142,401							
LIGHT CRUDE								
HEAVY CRUDE								
VOLUMETRIC LOSS	470		2,098		237		119	
C7 FRAC FRM NAT								
NATURAL C6'S								
85-145 LT ST RUN	-5,075							
FUEL GAS	-1,916		-1,186		-130		-80	
145-200 LT.ST RUN	-4,774							
200-330 STR.RUN	-16,538							
330-400 STR.RUN	-7,268						-175	
375-550 KEROSENE	-25,566							
LT.VIRGIN GAS OIL	-17,001							
REDUCED CRUDE	-64,262	63,096					1,166	
LT.VAC. GAS OIL		-8,693						
HVY.VAC. GAS OIL		-29,407						
930 PLUS VAC RESD		-24,997	15,727		7,629		1,640	
STM CRACK RESID.								
CAT SLURRY								
COKER FEED								
PROPYLENE			-215					
BUTYLENE			-149		-38			
LT. COKER GASO.			0					
HVY. COKER GASO.			-1,640					
COKER GAS OIL			-9,799					
COKER COKE			-3,730					
THERMAL CRK. TAR								
VIS BRKR RESID.					-3,738			
THERMAL PENTANES			-456		-15			
C66 LT. COKER GASO			-366					
PROPANE								
THERM.CRK. GASO								
THERMAL CRACK FEED								
C66 THERMAL GASO.					-308			
VISB. GASOLINE					-517			
VISBREAKER GAS OIL					-3,067			
C5-C6 HYDROCRAKATE								
HVY.HYDROCRACKATE								
HYDROCRACK DIST.							-363	
650+ H-OIL BTMS								

	FCRD	FVAC	FCKR	FTHM	FVBR	FHOL	FHKT	FVHK
650+HYDRFIN BT TCR							-935	935
650+HYDRFIN BT RSD							-1,373	
650-750 G.O.FM HOL								-141
750-930 LT.BTM HOL								-485
930+ BTMS FD HOL								-309
LT CYCLE OIL								
POOLED LGO AND SGO								
STM CRKD GAS OIL								
H2 TRTD KEROSENE								
CAT CRACKER FEED								
ETHANE								
FULL CUT CAT GASO								
HVY CYCLE OIL								
C5-250 LT.CAT								
250-410 HVY CAT								
CAT PENTANES								
C6-250 CAT. GASO.								
NORMAL PENTANE								
PROPYLENE ALKY.								
BUTYLENE ALKYLATE								
C6+ AML ALK								
ISO-PENTANE								
HEAVY ALKYLATE								
NC4-C4D FRM STM CR								
POLYMER GASO.								
H2 TRTD DIESEL								
TRTD LT.VAC G.O.								
TRTD HVY VAC G.O.								
TRTD COKER G.O.								
TRTD VISB G.O.								
TRTD LT CYCLE OIL								
REFORMER FEED								
BENZ RICH CUT								
C6-FBP RAFFINATE								
THERMAL GASO POOL								
H2 TRT LT. CRK NAP								
C6-250 CAT GASO.								
H2 TRTD HVY CAT								
TRTED THML GASOL.								
RAW PYROL GASO								
H2 TRT PYROL.GASO.								
105SEV REFORMATE								
100SEV REFORMATE								
95 SEV REFORMATE								
90 SEV REFORMATE								
85 SEV REFORMATE								
105 SEV FULL RFMT								
100 SEV FULL RFMT								
95 SEV FULL RFMT								

RGH-015

Bonner & Moore Associates, Inc.

	FCRD	FVAC	FCKR	FTHM	FVBR	FHØL	FHKT	FVHK
90 SEV FULL RFMT								
85 SEV FULL RFMT								
C5-IC6 RAFFINATE								
BENZENE								
TØLUENE								
XYLENE DISTILLATE								
HVY ARØ DISTILATE								
XYLENE								
HVY ARØMATICS								
TØLUENE DISTILLATE								
XYLENE TØWER FEED								
C5-IC6 PYRØL.GASØ.								
C7-400 PYRØL.GASØ.								
ISØ-HEXANE								
ETHYLENE ALKYLATE								
C5-145 CRD.NAP.								
145-200 CRD.NAP.								
200-330 CRD.NAP.								
MERØX TRTD HSR								
C5-400 THRM.GASØ.								
C5-400 VISB.GASØ.								
C5-430 CAT GASØ.								
C5-250 CAT GASØ								
250-410 CAT GASØ								
150-350 CØKER GASØ								
350-430 CØKER GASØ								
CAT PENTYLENES								
THERMAL PENTANES								
LPG FØR FUEL								
93 RØN MØTØR GASØ								
94 RØN MØTØR GASØ								
100 RØN MØTØR GASØ								
SPECIAL NAPHTHAS								
JP-4 NAPHTHA JET								
KERØSINE & JP-5								
DISTILLATE FUELS								
RESIDUAL FUEL ØIL								
	-------	-------	-------	-------	-------	-------	-------	-------
TØTALS	0	0	0		-0		0	0

UNIT OPERATIONS RECAP - VOLUME BASIS - BBL/CD

	FHCK	FCCU	FALK	FCPL	FHG0	FH2F	FHPT	FRFR
	HYDROCRACK	CAT CRACK	ALK C3-C5	CAT POLY	H2 TRT G.O	NAP. HDS	PYROL TRTR	CAT. REFRM
ETHYLENE								
NORMAL BUTANE	-537	-391	-141					-1,181
ISO-BUTANE	-1,296	-1,349	6,091					-724
NATURAL GASOLINE								
CRUDE								
LIGHT CRUDE								
HEAVY CRUDE								
VOLUMETRIC LOSS	2,873	4,181	-2,110		65	266		-451
C7 FRAC FRM NAT								
NATURAL C6'S								
85-145 LT ST RUN								
FUEL GAS	-409	-984				-240	-18	-1,623
145-200 LT.ST RUN						3,870		
200-330 STR.RUN						16,077		
330-400 STR.RUN						1,011		
375-550 KEROSENE					16,762			
LT.VIRGIN GAS OIL							-118	
REDUCED CRUDE								
LT.VAC. GAS OIL	6,737							
HVY.VAC. GAS OIL	3	27,506			1,898			
930 PLUS VAC FEED								
STM CRACK RESID.								
CAT SLURRY		-2,146						
COKER FEED								
PROPYLENE		-929	1,270					
BUTYLENE		-2,288	2,476					
LT. COKER GASO.								
HVY. COKER GASO.						1,640		
COKER GAS OIL								
COKER COKE								
THERMAL CRK. TAR								
VIS BRKR RESID.								
THERMAL PENTANES								
C66 LT. COKER GASO						366		
PROPANE	-0	-547						-1,869
THERM.CRK. GASO								
THERMAL CRACK FEED								
C66 THERMAL GASO.						308		
VISB. GASOLINE								
VISBREAKER GAS OIL								
C5-C6 HYDROCRAKATE	-3,257							
HVY.HYDROCRACKATE	-5,901				-287	6,188		
HYDROCRACK DIST.								
650+ H-OIL BTMS								

RGH-015

	FHCK	FCCU	FALK	FCPL	FHGO	FH2F	FHPT	FRFR
650+HYDRFIN BT TCR								
650+HYDRFIN BT RSD								
650-750 G.O.FM HOL								
750-930 LT.STM HOL								
930+ STMS FU HOL								
LT CYCLE OIL		-5,575			3,227			
POOLED LGO AND SGO								
STM CRKD GAS OIL	1,787							
H2 TRTD KEROSENE					-16,762			
CAT CRACKER FEED								
ETHANE		-306						
FULL CUT CAT GASO		-13,136						
HVY CYCLE OIL								
C5-250 LT.CAT		-1,840						
250-410 HVY CAT		-2,195						
CAT PENTANES								
C6-250 CAT. GASO.								
NORMAL PENTANE								
PROPYLENE ALKY.			-2,032					
BUTYLENE ALKYLATE			-6,327					
C6+ AML ALK								
ISO-PENTANE								
HEAVY ALKYLATE			-773					
NC4-C4U FRM STM CR			1,546					
POLYMER GASO.								
H2 TRTD DIESEL								
TRTD LT.VAC G.O.								
TRTD HVY VAC G.O.					-1,805			
TRTD COKER G.O.								
TRTD VISB G.O.								
TRTD LT CYCLE OIL					-3,098			
REFORMER FEED						-29,486		29,486
BENZ RICH CUT								
C6-FBP RAFFINATE								
THERMAL GASO POOL								
H2 TRT LT. CSK NAP						0		
C6-250 CAT GASO.								
H2 TRTD HVY CAT								
TRTED THML GASOL.								
RAW PYROL GASO							4,384	
H2 TRT PYROL.GASO.							-4,248	
105SEV REFORMATE								
100SEV REFORMATE								-7,437
95 SEV REFORMATE								-16,063
90 SEV REFORMATE								-138
85 SEV REFORMATE								
105 SEV FULL RFMT								
100 SEV FULL RFMT								
95 SEV FULL RFMT								

	FHCK	FCCU	FALK	FCPL	FHGO	FH2F	FHPT	FRFR
90 SEV FULL RFMT								
85 SEV FULL RFMT								
C5-160 RAFFINATE								
BENZENE								
TOLUENE								
XYLENE DISTILLATE								
HVY ARO DISTILLATE								
XYLENE								
HVY AROMATICS								
TOLUENE DISTILLATE								
XYLENE TOWER FEED								
C5-160 PYROL.GASO.								
C7-400 PYROL.GASO.								
ISO-HEXANE								
ETHYLENE ALKYLATE								
C5-145 CRD.NAP.								
145-200 CRD.NAP.								
200-330 CRD.NAP.								
MEROX TRTD HSR								
C5-400 THRM.GASO.								
C5-400 VISB.GASO.								
C5-430 CAT GASO.								
C5-250 CAT GASO								
250-430 CAT GASO								
150-350 COKER GASO								
350-430 COKER GASO								
CAT PENTYLENES								
THERMAL PENTANES								
LPG FOR FUEL								
93 RON MOTOR GASO								
94 RON MOTOR GASO								
100 RON MOTOR GASO								
SPECIAL NAPHTHAS								
JP-4 NAPHTHA JET								
KEROSINE & JP-5								
DISTILLATE FUELS								
RESIDUAL FUEL OIL								
	-------	-------	-------	-------	-------	-------	-------	-------
TOTALS	-0	0	-0		-0	0	-0	-0

UNIT OPERATIONS RECAP - VOLUME BASIS - BBL/CD

	FRFM	FARO	FCUT	FDAK	FISM	FLA2	F3UK	FI4K
	REFMATE TR	AROM SEP.	BZ HRTCUT	HYDRODEALK	C4-C6 ISOM	C2U ALKLAT	PROPENE DP	IC4 CRACKR
ETHYLENE								
NORMAL BUTANE					1,118			
ISO-BUTANE					-1,011			
NATURAL GASOLINE								
CRUDE								
LIGHT CRUDE								
HEAVY CRUDE								
VOLUMETRIC LOSS				54	-16			
C7 FRAC FRM NAT								
NATURAL C6'S								
85-145 LT ST RUN								
FUEL GAS				-302	-20			
145-200 LT.ST RUN								
200-330 STR.RUN								
330-400 STR.RUN								
375-550 KEROSENE								
LT.VIRGIN GAS OIL								
REDUCED CRUDE								
LT.VAC. GAS OIL								
HVY.VAC. GAS OIL								
930 PLUS VAC RESD								
STM CRACK RESID.								
CAT SLURRY								
COKER FEED								
PROPYLENE								
BUTYLENE								
LT. COKER GASO.								
HVY. COKER GASO.								
COKER GAS OIL								
COKER COKE								
THERMAL CRK. TAR								
VIS BRKR RESID.								
THERMAL PENTANES								
C6& LT. COKER GASO								
PROPANE								
THERM.CRK. GASO								
THERMAL CRACK FEED								
C6& THERMAL GASO.								
VISB. GASOLINE								
VISBREAKER GAS OIL								
C5-C6 HYDROCRAKATE								
HVY.HYDROCRACKATE								
HYDROCRACK DIST.								
650+ H-OIL BTMS								

USA, EX CALIF, YEAR 1980, SCHEDULE A   PEAK PERIBD RUN   PRIBR YEAR IS 1970   1 18 2

	FRFM	FAR8	FCUT	FDAK	FISM	FLA2	F3UK	FI4K
650+HYDRFIN BT TCR								
650+HYDRFIN BT RSD								
650-750 G.B.FM HBL								
750-930 LT.STM HBL								
930+ BTMS FU HBL								
LT CYCLE BIL								
PBBLED LGB AND SGB								
STM CRKD GAS BIL								
H2 TRTD KERBSENE								
CAT CRACKER FEED								
ETHANE								
FULL CUT CAT GASB								
HVY CYCLE BIL								
C5-250 LT.CAT								
250-410 HVY CAT								
CAT PENTANES								
C6-250 CAT. GASB.								
NBRMAL PENTANE								
PRBPYLENE ALKY.								
BUTYLENE ALKYLATE								
C6+ AML ALK								
ISB-PENTANE					-72			
HEAVY ALKYLATE								
NC4-C4U FRM STM CR								
PBLYMER GASB.								
H2 TRTD DIESEL								
TRTD LT.VAC G.B.								
TRTD HVY VAC G.B.								
TRTD CBKER G.B.								
TRTD VISB G.B.								
TRTD LT CYCLE BIL								
REFBRMER FEED								
BENZ RICH CUT								
C6-FBP RAFFINATE		-1,769						
THERMAL GASB PBBL								
H2 TRT LT. CBK NAP								
C6-250 CAT GASB.								
H2 TRTD HVY CAT								
TRTED THML GASBL.								
RAW PYRBL GASB								
H2 TRT PYRBL.GASB.								
105SEV REFBRMATE								
100SEV REFBRMATE		7,437						
95 SEV REFBRMATE	12,200	3,862						
90 SEV REFBRMATE	138							
85 SEV REFBRMATE								
105 SEV FULL RFMT								
100 SEV FULL RFMT								
95 SEV FULL RFMT	-12,200							

USA, EX CALIF, YEAR 1980, SCHEDULE A   PEAK PERIOD RUN   PRIOR YEAR IS 1970   1 18 3

	FRFM	FARO	FCUT	FOAK	FISM	FLA2	F3UK	FI4K
90 SEV FULL RFMT	-138							
85 SEV FULL RFMT								
C5-IC6 RAFFINATE		-494						
BENZENE		-697		-1,114				
TOLUENE		-2,141		1,362				
XYLENE DISTILLATE								
HVY ARS DISTILATE								
XYLENE		-2,097						
HVY AROMATICS		-2,201						
TOLUENE DISTILLATE								
XYLENE TOWER FEED		-1,900						
C5-IC6 PYROL.GASO.								
C7-400 PYROL.GASO.								
ISO-HEXANE								
ETHYLENE ALKYLATE								
C5-145 CRD.NAP.								
145-200 CRD.NAP.								
200-330 CRD.NAP.								
MEROX TRTD HSR								
C5-400 THRM.GASO.								
C5-400 VISB.GASO.								
C5-430 CAT GASO.								
C5-250 CAT GASO								
250-410 CAT GASO								
150-350 COKER GASO								
350-430 COKER GASO								
CAT PENTYLENES								
THERMAL PENTANES								
LPG FOR FUEL								
93 RON MOTOR GASO								
94 RON MOTOR GASO								
100 RON MOTOR GASO								
SPECIAL NAPHTHAS								
JP-4 NAPHTHA JET								
KEROSINE & JP-5								
DISTILLATE FUELS								
RESIDUAL FUEL OIL								
TOTALS	-0	-0		0	0			

UNIT OPERATIONS RECAP - VOLUME BASIS - BBL/CD

	FH2M	FH2P	FMRX
	H2 MANUFAC	H2 PURIFCT	MEROX TRT
ETHYLENE			
NORMAL BUTANE			
ISO-BUTANE			
NATURAL GASOLINE			
CRUDE			
LIGHT CRUDE			
HEAVY CRUDE			
VOLUMETRIC LOSS		0	
C7 FRAC FRM NAT			
NATURAL C6'S			
85-145 LT ST RUN			5,075
FUEL GAS		-0	
145-200 LT.ST RUN			904
200-330 STR.RUN			461
330-400 STR.RUN			6,432
375-550 KEROSENE			
LT.VIRGIN GAS OIL			
REDUCED CRUDE			
LT.VAC. GAS OIL			
HVY.VAC. GAS OIL			
930 PLUS VAC RESD			
STM CRACK RESID.			
CAT SLURRY			
COKER FEED			
PROPYLENE			
BUTYLENE			
LT. COKER GASO.			
HVY. COKER GASO.			
COKER GAS OIL			
COKER COKE			
THERMAL CRK. TAR			
VIS BRKR RESID.			
THERMAL PENTANES			471
C65 LT. COKER GASO			
PROPANE			
THERM.CRK. GASO			
THERMAL CRACK FEED			
C65 THERMAL GASO.			
VISB. GASOLINE			517
VISBREAKER GAS OIL			
C5-C6 HYDROCRAKATE			
HVY.HYDROCRACKATE			
HYDROCRACK DIST.			
650+ H-OIL BTMS			

USA, EX CALIF, YEAR 1980, SCHEDULE A   PEAK PERIØD RUN   PRIØR YEAR IS 1970   1 19 2

	FH2M	FH2P	FMRX
650+HYDRFIN BT TCR			
650+HYDRFIN BT RSD			
650-750 G.Ø.FM HØL			
750-930 LT.BTM HØL			
930+ BTMS FD HØL			
LT CYCLE ØIL			
PØØLED LGØ AND SGØ			
STM CRKD GAS ØIL			
H2 TRTD KERØSENE			
CAT CRACKER FEED			
ETHANE			
FULL CUT CAT GASØ			13,136
HVY CYCLE ØIL			
C5-250 LT.CAT			1,840
250-410 HVY CAT			2,195
CAT PENTANES			
C6-250 CAT. GASØ.			
NØRMAL PENTANE			
PRØPYLENE ALKY.			
BUTYLENE ALKYLATE			
C6+ AML ALK			
ISØ-PENTANE			
HEAVY ALKYLATE			
NC4-C4U FRM STM CR			
PØLYMER GASØ.			
H2 TRTD DIESEL			
TRTD LT.VAC G.Ø.			
TRTD HVY VAC G.Ø.			
TRTD CØKER G.Ø.			
TRTD VISB G.Ø.			
TRTD LT CYCLE ØIL			
REFØRMER FEED			
BENZ RICH CUT			
C6-FBP RAFFINATE			
THERMAL GASØ.PØØL			
H2 TRT LT. CØK NAP			
C6-250 CAT GASØ.			
H2 TRTD HVY CAT			
TRTED THML GASØL.			
RAW PYRØL GASØ			
H2 TRT PYRØL.GASØ.			
105SEV REFØRMATE			
100SEV REFØRMATE			
95 SEV REFØRMATE			
90 SEV REFØRMATE			
85 SEV REFØRMATE			
105 SEV FULL RFMT			
100 SEV FULL RFMT			
95 SEV FULL RFMT			

	FH2M	FH2P	FMRX
90 SEV FULL RFMT			
85 SEV FULL RFMT			
C5-IC6 RAFFINATE			
BENZENE			
TOLUENE			
XYLENE DISTILLATE			
HVY ARO DISTILATE			
XYLENE			
HVY AROMATICS			
TOLUENE DISTILLATE			
XYLENE TOWER FEED			
C5-IC6 PYROL.GASO.			
C7-400 PYROL.GASO.			
ISO-HEXANE			
ETHYLENE ALKYLATE			
C5-145 CRD.NAP.			-5,075
145-200 CRD.NAP.			-904
200-330 CRD.NAP.			-461
MEROX TRTD HSR			-6,432
C5-400 THRM.GASO.			
C5-400 VISB.GASO.			-517
C5-430 CAT GASO.			-13,136
C5-250 CAT GASO			-1,840
250-410 CAT GASO			-2,195
150-350 COKER GASO			
350-430 COKER GASO			
CAT PENTYLENES			
THERMAL PENTANES			-471
LPG FOR FUEL			
93 RON MOTOR GASO			
94 RON MOTOR GASO			
100 RON MOTOR GASO			
SPECIAL NAPHTHAS			
JP-4 NAPHTHA JET			
KEROSINE & JP-5			
DISTILLATE FUELS			
RESIDUAL FUEL OIL			
	--------	--------	--------
TOTALS			-0

RGH-015

OPERATIONS SUMMARY - VOLUME BASIS - BBL/CD

	PURCHASES	UNITS	REC BLN	SPEC BLN	SALES	V/W CONV	TOTALS		INCR VAL
ETHYLENE								C2U	3.499
NORMAL BUTANE	-1,952	-1,633	44	3,540			0	NC4	2.661
ISO-BUTANE	-1,405	1,405					-0	IC4	4.019
NATURAL GASOLINE	-4,060			4,060				NAT	3.652
CRUDE	-142,401	142,401						CRD	3.625
LIGHT CRUDE								CRL	3.714
HEAVY CRUDE								CRH	3.573
VOLUMETRIC LOSS		7,786			-7,786		-0	LOS	
C7 FRAC FRM NAT								NT7	4.032
NATURAL C6'S								NT6	4.178
85-145 LT ST RUN		0					0	LLR	3.505
FUEL GAS		-6,906			6,906		0	FGS	2.930
145-200 LT.ST RUN		0					0	LSR	4.103
200-330 STR.RUN		0					0	MSR	4.185
330-400 STR.RUN		0					0	HSR	4.243
375-550 KEROSENE		-8,803		8,803				KER	4.105
LT.VIRGIN GAS OIL		-17,120		4,073		13,047	0	LVO	4.105
REDUCED CRUDE		0					0	TCR	3.520
LT.VAC. GAS OIL		-1,956				1,956	-0	LGO	4.185
HVY.VAC. GAS OIL		0					0	HVO	4.117
930 PLUS VAC RESD		0					0	RSD	3.040
STM CRACK RESID.				1,716		-1,716		STR	3.173
CAT SLURRY		-2,146		2,146			0	SLP	2.934
COKER FEED								KFD	4.228
PROPYLENE		126				-126	0	C3U	1.655
BUTYLENE		0					0	C4U	2.805
LT. COKER GASO.		0					0	LKN	3.635
HVY. COKER GASO.		0					0	HKN	4.006
COKER GAS OIL		-9,799		9,799				KGO	4.105
COKER COKE		-3,730				3,730	0	COK	1.057
THERMAL CRK. TAR								TCF	3.383
VIS BRKR RESID.		-3,738		3,738			0	VBR	2.599
THERMAL PENTANES		0					0	C5T	3.882
C6S LT. COKER GASO								LK6	3.573
PROPANE		-2,417	760			1,656	0	C3S	2.031
THERM.CRK. GASO								TCG	4.583
THERMAL CRACK FEED								TFD	1.461
C6S THERMAL GASO.								TC6	3.503
VISB. GASOLINE								VBG	3.502
VISBREAKER GAS OIL		-3,067		3,067				VBO	4.105
C5-C6 HYDROCRAKATE		-3,257		3,257			0	LHC	4.669
HVY.HYDROCRACKATE		0					0	HHC	4.589
HYDROCRACK DIST.		-363		363				HCD	4.288
650+ H-OIL BTMS								HBH	3.521

	PURCHASES	UNITS	REC BLN	SPEC BLN	SALES	V/W CONV	TOTALS		INCR VAL
650+HYDRFIN BT TCR		0					0	HBB	3.558
650+HYDRFIN BT RSD		-1,373		1,373			0	HBF	3.004
650-750 S.G.FM HBL		-141		141				HLG	4.288
750-930 LT.BTM HBL		-465		465				HLB	4.288
930+ BTMS FU HBL		-309		309				HHB	2.840
LT CYCLE OIL		-2,347		2,347			0	LCO	4.105
POOLED LGO AND SGO								GSO	4.185
STM CRKD GAS OIL		1,787				-1,787		SGO	4.122
H2 TRTD KEROSENE		-16,762	3,186	13,577				KHR	4.350
CAT CRACKER FEED								CFD	-1.442
ETHANE		-306				306	0	C2S	2.092
FULL CUT CAT GASO		0					0	FCG	4.889
HVY CYCLE OIL								HCO	3.520
C5-250 LT.CAT								LCG	4.581
250-410 HVY CAT		0					0	HCG	5.474
CAT PENTANES								CC5	4.337
C6-250 CAT. GASO.								LCD	4.256
NORMAL PENTANE								NC5	3.180
PROPYLENE ALKY.		-2,032		2,032			0	LA3	5.582
BUTYLENE ALKYLATE		-6,327		6,327			-0	LA4	5.993
C6+ AML ALK								LA5	7.051
ISO-PENTANE		-72		72			0	IC5	4.800
HEAVY ALKYLATE		-773		773			0	HVA	4.350
NC4-C4L FR STM CR		1,546				-1,546		SC4	2.792
POLYMER GASO.								POL	6.188
H2 TRTD DIESEL								SDS	4.318
TRTD LT.VAC G.O.								SLG	4.288
TRTD HVY VAC G.O.		-1,805		1,805				SHV	4.288
TRTD COKER G.O.								SKO	4.288
TRTD VISB G.O.								SVO	4.288
TRTD LT CYCLE OIL		-3,098		3,098			0	SCY	4.288
REFORMER FEED		0					0	RF1	3.742
BENZ RICH CUT								SBN	5.121
C6+FRR RAFFINATE		-1,769		1,769			0	HRF	4.304
THERMAL GASO POOL								TCC	
H2 TRT LT. CSK NAP		0					0	TLK	3.929
C6-250 CAT GASO.								DLC	4.592
H2 TRTD HVY CAT								HCH	
TRTED THML GASOL.								TCH	
RAW PYROL GASO		4,384				-4,384		PYR	5.276
H2 TRT PYROL.GASO.		-4,248		4,248				SCN	5.847
105SEV REFORMATE								F05	6.766
100SEV REFORMATE								F00	5.925
95 SEV REFORMATE		0					0	F95	5.530
90 SEV REFORMATE		0					0	F90	5.320
85 SEV REFORMATE								F85	5.171
105 SEV FULL RFMT								S05	6.788
100 SEV FULL RFMT								S00	5.943
95 SEV FULL RFMT		-12,200		12,200				S95	5.543

USA, EX CALIF, YEAR 1980, SCHEDULE A   PEAK PERIOD RUN   PRIOR YEAR IS 1970   1 20 3

	PURCHASES	UNITS	REC BLN	SPEC BLN	SALES	V/W CONV	TOTALS		INCR VAL
90 SEV FULL RFMT		-138		138				S90	5.331
85 SEV FULL RFMT								S85	5.119
C5-IC6 RAFFINATE		-494		494				LRF	4.948
BENZENE		-1,811				1,811	0	BNZ	9.258
TOLUENE		-779		600		179	0	TOL	7.187
XYLENE DISTILLATE								X95	6.098
HVY ARO DISTILATE								H95	5.835
XYLENE		-2,097		1,680		418	0	XYL	6.780
HVY AROMATICS		-2,201		2,201			0	HAR	6.816
TOLUENE DISTILLATE								T95	5.817
XYLENE TOWER FEED		-1,900		1,900			0	XYH	6.119
C5-IC6 PYROL.GASO.								LSC	4.675
C7-400 PYROL.GASO.								HSC	7.141
ISO-HEXANE								IC6	5.545
ETHYLENE ALKYLATE								LA2	6.148
C5-145 CRD.NAP.		-5,075	175	4,901				LLM	3.613
145-200 CRD.NAP.		-904	159	745			0	LSM	4.210
200-330 CRD.NAP.		-461	461					MSM	4.292
MEROX TRTD HSR		-6,432	1,297	5,135				HSM	4.350
C5-400 THRM.GASO.								TCM	4.690
C5-400 VISB.GASO.		-517		517				VBM	3.609
C5-430 CAT GASO.		-13,136		13,136			-0	FCM	4.997
C5-250 CAT GASO		-1,840		1,840				LCM	4.689
250-410 CAT GASO		-2,195		2,195				HCM	5.582
150-350 COKER GASO								LKM	3.633
350-430 COKER GASO								HKM	4.114
CAT PENTYLENES								CCM	4.444
THERMAL PENTANES		-471		471				C5M	3.990
LPG FOR FUEL			-804		804			LGF	2.065
93 RON MOTOR GASO				-47,179	47,180		0	M91	
94 RON MOTOR GASO				-19,307	19,307		0	M94	
100 RON MOTOR GASO				-1,837	1,837		0	MPR	
SPECIAL NAPHTHAS			-3,689		3,689			SPN	4.350
JP-4 NAPHTHA JET			-1,588		1,588			JP4	4.238
KEROSINE & JP-5				-18,444	18,444		0	LDF	
DISTILLATE FUELS				-34,660	34,660		0	DST	
RESIDUAL FUEL OIL				-9,644	9,644			RFO	
TOTALS	-149,818	-0	-0	-1	136,274	13,544			

USA, EX CALIF, YEAR 1980, SCHEDULE A   PEAK PERIOD RUN   PRIOR YEAR IS 1970   1 21 1

UTILITY SUMMARY

	FDR	STM	KWH	H2O	FUL	CRC	
OPERATIONS	THRUPUT	STEAM M-LB	ELEC PWR KWH	COOL H2O M-GAL	FUEL GAS MM-BTU	CHEM ETC DOLLARS	TOTAL $/CD
CRUDE DIST	142,401		109,649	3,275	15,379		-8,171
VACUUM	63,096	1,262	31,548		3,786		-2,054
COKER DELD	15,727	-793	57,371	1,663	4,300		-2,533
VISBREAKER	7,952	229	15,259	5,341	1,526		-851
H.O.HYDRSF	2,806	185	11,168		221	379	-586
VAC HYDR S	935	22	552		75		-40
HYDROCRACK	8,527	241	119,372	10,061	5,259	529	-4,084
CAT CRACK	27,506	-391	83,022	16,649		2,063	-2,835
ALK C3-C5	9,132	101	34,247	33,488	9,543	274	-5,030
H2 TRT G.O	21,838	66	67,326		2,430	44	-1,800
NAP. HDS	25,844	462	26,742	3,907	811	1,233	-1,859
PYROL TRTR	4,384	487	3,069	2,017	548	88	-371
CAT. REFRM	29,486		88,477	19,376	9,629	3,073	-8,373
AROM SEP.	11,299	1,174	8,025	2,736	369	51	-297
HYDRODEALK	1,362			1,035	441		-205
C4-C6 ISOM	1,118	730	1,653	1,610		302	-317
H2 PURIFCT	9	0	3				-0
MEROX TRT	31,031	140	6				-0
SULFUR PLT	57	-154	0		68		-32
UTILITIES	104,920	-3,762	194,848	-101,158	4,890	4,767	-8,853
TOTAL	512,477	-0	852,336	-0	59,275	12,802	
UNIT COST $/UNIT			-0.009		-0.465	-1.000	
TOTAL $/CD			-7,927		-27,563	-12,802	

TOTAL ALL UTILITIES = -48,292

USA, EX CALIF, YEAR 1980, SCHEDULE A PEAK PERIOD RUN PRIOR YEAR IS 1970 1 22 1

OVERALL ECONOMIC SUMMARY

		$/CD	Ms/YR
FROM WEIGHT BASIS SUMMARY			
SALES	100,980		
PURCHASES	-2,717		

NET		98,264	35,866
FROM VOLUME BASIS SUMMARY			
SALES	601,056		
PURCHASES	-541,022		

NET		60,034	21,913
UTIL & MISC OPER COSTS		-48,292	-17,627
TEL PURCHASES		-5,326	-1,944
		--------	--------
NET OPERATING REVENUE		104,679	38,208
NEW EQUIPMENT EXPENSES			
MAINTENANCE	-9,216		
INS,TAX,OHD	-3,072		

TOTAL UNITS		-12,288	-4,485
		--------	--------
TOTAL NEW EQUIPMENT EXP		-12,288	-4,485
		========	========
NET OPER PROFIT		92,391	33,723
CAPITAL RECOVERY			
UNITS		-28,571	-10,429
		--------	--------
TOTAL		-28,571	-10,429
		========	========
NET REVENUE		63,820	23,294

APPENDIX C

COMMENTS ON OTHER SCHEDULES OF THE RFP

APPENDIX C

COMMENTS ON OTHER SCHEDULES OF THE RFP

In addition to the four schedules discussed in detail in the body of this report, the RFP identified nine other schedules. These were either intermediate in their impact to the four schedules or, as in the case of Schedules E and K, were impossible to achieve within the forecasted construction industry capacity. Except for Schedules C, D, F and I, every schedule created a business cycle in the process construction industry. Moreover, each schedule caused a growth rate in the early years which exceeded the industry's capacity.

With the results derived from the detailed studies, it is possible to predict by interpolation some of the consequences of the nine schedules not studied in detail. Specifically, the TEL requirements, aromatic contents of gasoline, and refining investments have been estimated. Spot checks have been run to confirm these approximations.

Table C-1 presents the lead requirements for these schedules. Table C-2 presents the estimates of aromatics burned in pre-1975 vehicles and Table C-3 presents the projected investment requirements.

TABLE C-1

LEAD REQUIREMENTS

(Thousand Tons/Year)

Schedule	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
B	207	190	155	106	62	54	46	39	33	27
C	207	122	75	53	39	35	31	28	25	22
D	119	112	106	89	77	66	56	47	38	31
E	207	190	189	176	158	0	0	0	0	0
F	207	146	106	89	77	66	56	47	38	31
H	119	88	85	36	30	25	20	15	11	8
I	119	88	65	18	15	12	10	7	5	4
J	119	65	54	9	8	6	5	4	3	2
K	119	88	85	36	30	0	0	0	0	0

TABLE C-2

AROMATICS BURNED IN PRE-1975 VEHICLES

(Million Barrels/Year)

Schedule	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
B	490	510	550	600	580	520	450	400	340	280
C	490	550	630	690	620	550	490	420	360	290
D	560	570	600	630	560	500	440	390	340	270
E	490	510	530	550	480	740	640	550	460	370
F	490	540	600	620	560	500	440	360	340	270
H	560	610	630	780	740	680	630	570	500	480
I	560	610	660	910	830	740	670	600	520	480
J	560	640	700	960	850	770	690	620	530	490
K	560	610	630	780	740	790	710	630	540	500

TABLE C-3

REFINING INVESTMENT
(Million Dollars/Year)

SCHEDULE B

YEAR	FOREIGN	CANADA	US	TOTAL
1971	125	127	1,158	1,411
1972	140	70	635	845
1973	150	179	1,624	1,953
1974	160	226	2,052	2,438
1975	170	231	2,097	2,497
1976	180	128	1,160	1,468
1977	185	131	1,188	1,503
1978	190	132	1,202	1,525
1979	195	132	1,199	1,526
1980	200	133	1,213	1,547

SCHEDULE C

	FOREIGN	CANADA	US	TOTAL
1971	125	127	1,158	1,411
1972	140	70	635	845
1973	150	158	1,435	1,742
1974	160	171	1,556	1,888
1975	170	157	1,423	1,750
1976	180	117	1,064	1,361
1977	185	122	1,108	1,415
1978	190	123	1,120	1,434
1979	195	125	1,135	1,455
1980	200	126	1,148	1,475

SCHEDULE D

	FOREIGN	CANADA	US	TOTAL
1971	125	127	1,158	1,411
1972	140	70	635	845
1973	150	138	1,252	1,540
1974	160	189	1,719	2,068
1975	170	145	1,322	1,637
1976	180	127	1,150	1,457
1977	185	133	1,206	1,524
1978	190	134	1,221	1,546
1979	195	131	1,191	1,517
1980	200	133	1,206	1,538

TABLE C-3 (cont.)

SCHEDULE E

YEAR	FOREIGN	CANADA	US	TOTAL
1971	125	127	1,158	1,411
1972	140	70	635	845
1973	150	149	1,358	1,658
1974	160	168	1,530	1,858
1975	170	176	1,603	1,949
1976	180	353	3,212	3,746
1977	185	122	1,106	1,412
1978	190	122	1,110	1,422
1979	195	123	1,122	1,440
1980	200	123	1,117	1,440

SCHEDULE F

	FOREIGN	CANADA	US	TOTAL
1971	125	127	1,158	1,411
1972	140	70	635	845
1973	150	205	1,860	2,214
1974	160	167	1,516	1,843
1975	170	146	1,326	1,642
1976	180	128	1,167	1,475
1977	185	133	1,213	1,532
1978	190	133	1,210	1,533
1979	195	134	1,216	1,545
1980	200	133	1,213	1,547

SCHEDULE H

	FOREIGN	CANADA	US	TOTAL
1971	125	127	1,158	1,411
1972	140	70	635	845
1973	150	156	1,414	1,719
1974	160	248	2,251	2,659
1975	170	158	1,435	1,762
1976	180	120	1,095	1,395
1977	185	127	1,156	1,469
1978	190	128	1,162	1,480
1979	195	127	1,158	1,480
1980	200	127	1,154	1,481

<u>TABLE C-3 (cont.)</u>

SCHEDULE I

YEAR	FOREIGN	CANADA	US	TOTAL
1971	125	127	1,158	1,411
1972	140	70	635	845
1973	150	201	1,830	2,181
1974	160	158	1,433	1,751
1975	170	155	1,407	1,732
1976	180	117	1,068	1,365
1977	185	122	1,113	1,420
1978	190	122	1,108	1,420
1979	195	122	1,113	1,430
1980	200	123	1,117	1,439

SCHEDULE J

	FOREIGN	CANADA	US	TOTAL
1971	125	127	1,158	1,411
1972	140	70	635	845
1973	150	160	1,452	1,762
1974	160	227	1,067	1,454
1975	170	138	1,255	1,563
1976	180	116	1,052	1,348
1977	185	121	1,097	1,402
1978	190	120	1,092	1,402
1979	195	122	1,105	1,421
1980	200	119	1,082	1,401

SCHEDULE K

	FOREIGN	CANADA	US	TOTAL
1971	125	127	1,158	1,411
1972	140	70	635	845
1973	150	156	1,414	1,719
1974	160	248	2,251	2,659
1975	170	158	1,435	1,762
1976	180	163	1,486	1,830
1977	185	118	1,075	1,379
1978	190	120	1,088	1,397
1979	195	122	1,109	1,426
1980	200	123	1,132	1,445

APPENDIX D

MARKETING CHARACTERISTICS OF OIL COMPANIES

MARKETING CHARACTERISTICS OF OIL COMPANIES

OIL COMPANY	TOTAL BRANDED OUTLETS	COMMITTED CONVERSION	PROJECTED CONVERSIONS @ 65.8%	STATION CONVERSION $ @ $8030	TERMINALS TOTAL	TERMINALS CONVERSIONS @ 40%	TERMINAL CONVERSION COST @ $150,000	TOTAL CONVERSION COST
Gulf	31271	25000					$MM	$MM
Humble	29427	20000			485	194	29	510 - not included in lead decisions
Std Oil-Cal	8217	5000						
Std Oil-Ky	8254							
Phillips (65%)	13842			$MM				
25.5% Group 1	91011		59885	481				
Amoco	29702	11000						
Arco	22778	22778						
Murphy	1282							
Shell	22000	11000						
Texaco	40230							
Marathon	3615	2000						
Std Oil-Ohio	3100	96778						
BP Oil	9700	147,010						
Boron	475	÷ 65.8%						
Fleetwing	290							$MM
37.4% Group 2	133172		87627	703	711	284	43	746 - already committed → 746 as result of lead decisions
Cities Service	9459							
Conoco	6900							
Mobil	25513							
Phillips (35%)	7454							
Sun	16900							
Union 76	16426							
23.2% Group 3	82652		54385	437	441	176	26	463 - incremental cost → 463 to go to 3 grades
Others 13.9% Group 4	49473		0	0	265	0	0	0
Total	356308		201897	1621	1902	654	98	1719
New Construction			65.8% 3-grade	$8030 incremental				
4000/yr x 4 yrs (1972-75)	16000		10528	85				85 - incremental cost → 85 to go to 3 grades
								Uncommitted 548 (463+85)
								Committed 746
								Total 1294

APPENDIX E

CAPITAL RECOVERY FACTOR

APPENDIX E

CAPITAL RECOVERY FACTOR

Premises:

1) Economic Life: 16 years.

2) Depreciation for Income Tax: 16 years Double Declining.

3) Income Tax Rate: 48%.

4) Investment Service Cost - Maintenance, Insurance, Taxes and Overhead: 8%.

5) Rate of Return on Investment: 10% DCF.

Notation:

1) G for Capital Recovery Factor including Income Tax and Investment Service Cost.

2) C for Capital Recovery Factor with no Income Tax. For 16 years/ 10% = .1278[1]. C modified for Double Declining Depreciation = .1278 - .0066T = .1246.

3) D for Depreciation on SL basis. For 16 years .0625.

4) T for Income Tax. At 48% is .48.

5) S for Investment Service Cost comprising of Maintenance, Insurance, Taxes and Overhead.

6) P for Investment in Plant = $1.00.

---

[1] $C = \frac{i\,(1+i)^n}{(1+i)^n - 1}$.: Where i is 10% and n is 16 years: C = .1278.

Derivation:

$$G = \frac{PC - TDP}{1-T} + SP$$

$$= \frac{.1246 - (.48)\ (.0625)}{1 - .48} + .08$$

$$= .1819 + .08$$

$$= .2619$$

APPENDIX F

GLOSSARY OF TERMS

APPENDIX F

GLOSSARY OF TERMS

Alkylation — A process for the manufacture of high-octane gasoline by the addition of an alkyl radical to an olefin to produce a saturated isoparaffin. Sulfuric or hydrofluoric acids are the usual catalysts.

A.P.I. Gravity — A density scale commonly used in the petroleum industry in America; related to specific gravity by the equation:

sp. gr: at 60°/60°F = 141.5/(131.5 + API°)

Water with 1.0 sp. grav. = 10° API and the lower the sp. grav., the higher the API gravity.

Base Stock — A component in a blend which serves no unique purpose.

Blending Octane Number — The apparent octane number of a component when blended with other components; not necessarily the same as the octane number determined by testing the unblended material.

Catalytic Cracking — A process for converting high molecular weight hydrocarbons into lower boiling hydrocarbons. The process is catalyzed by an alumna-silca type catalyst.

Charge — The material fed or to be fed into a process unit.

Cracking — A process for changing the chemical composition of a petroleum fraction wherein the product is predominantly lighter in molecular weight and lower in boiling range than the feed. The older cracking processes are thermal whereas more recently catalytic cracking processes have been perfected. Catalytic cracking has the advantage over thermal cracking in that the yield of more valuable products are greater and the naphtha has a higher octane rating. For these reasons catalytic cracking is generally preferred despite the greater complexity and cost of the equipment.

Debutanizer — The fractionator where butane and any lighter hydrocarbon is removed from higher boiling material.

Dehydrogenation

The removal of hydrogen atoms from a molecule yielding an unsaturated material, e.g., olefins, diolefins, aromatics.

Distillate

Any overhead product of distillation.

Distillation

An operation in which oils are separated into products of shorter boiling range by successive vaporization and condensation, usually in a bubble plate fractionating tower. Rerun distillation refers to the refractionation of a distillate to recover special boiling range stocks or to remove undesirable fraction products resulting from preceding processing steps. Extractive distillation permits the separation of close boiling compounds by the addition of another component to modify the relative volatilities of the original materials. Superfractionation is a term used to describe a distillation operation in which at least one of the products is a relatively pure compound. Stabilization refers to a distillation carried out to remove light ends from a heavier fraction.

End-point

(1) The highest vapor temperature reached during a distillation in which all components are vaporized.
(2) The state of completion of some chemical reaction.
That material which is removed by extraction.

Flash

(1) To distill by equilibrium vaporization in which all the vapor formed remains in contact with the residual liquid during the vaporization process.
(2) To ignite momentarily a combustible mixture of vapor and air. The momentary burning of a mixture of combustible vapor and air.

Flash Point

Lowest temperature at which a substance gives off enough vapors under controlled conditions to produce a momentary flash of fire when a small flame is passed near its surface.

Fuel Oil

Any petroleum liquid product used to produce heat as in a stove, furnace, or boiler.

Gas Oil	Any petroleum distillate boiling approximately between gasoline end point and 700°F; so named because originally used in carbureting water gas.
Gasoline	A mixture of hydrocarbons whose ASTM distillation range is approximately 90 to 425°F. Finished gasoline contains certain additives such as tetraethyl lead, metal deactivators, oxidation inhibitors, and dye.
Gravity	Density; usually refers to °API, a density scale which is related to specific gravity by the following formula: $°API = \frac{141.5}{\text{sp. gr. at } 60°/60°F} 131.5$
Intermediate	Any process material that is in an unfinished state.
Lead Susceptibility	Broadly defined is a measure of the effectiveness of tetraethyl lead in improving the antiknock properties of a gasoline.
Light Ends	Any material boiling considerably lower than the major part of the oil in question.
Naphtha	A loose term referring to almost any virgin or straight run* distillate boiling below the kerosene range; often, materials boiling below approximately 200°F are excluded from naphtha. *Has not been cracked.
Natural Gasoline	Gasoline condensed from a mixture of lower paraffin hydrocarbon gases saturated with vapors of low boiling liquid hydrocarbon, the mixture occurring naturally in petroleum fields.
Octane Number	An arbitrary scale for engine knock rating of gasolines, based on volume percentage of isooctane in a blend with *n*-heptane which shows the same knocking as the motor fuel under test.
Octane Number, Clear	The octane number of a component or blend without TEL fluid.

Pour Point	The temperature at which an oil ceases to flow when cooled under specific conditions.
Raffinate	Material from which some substance has been removed by extraction.
Reforming	A process that uses gasoline boiling range material as the charge stock for the conversion of low octane straight run naphtha to higher octane material by molecular arrangement and cracking.
Reid Vapor Pressure	Approximately the absolute vapor pressure (expressed in pounds per square inch) of a material under specified test conditions.
Rerun	To redistill.
Research Octane	An engine knock rating scale (F-1) based on isooctane as 100 and n-heptane as zero. Differs from motor method octane numbers in the speed of the test engine, spark advance setting and intake air temperature. Research octane ratings are usually higher than motor octane ratings depending on hydrocarbon type.
Residue	The bottom product from a column; usually refers to heavy, black material.
Road Octane Number	The apparent octane number of a gasoline in a passenger car engine in actual, controlled operation. Road performance and road rating are related terms.
Straight Run	Hydrocarbon material that has not been cracked or synthesized.
Sweet	Containing insufficient mercaptan or sulfide sulfur to be detected.
Sweetening	Any of several available processes which render petroleum products sweet to the doctor test.
Thermal Cracking	A process for pyrolysis of hydrocarbons into lighter products. Concomitantly a small amount of heavier products is also formed by molecular condensation.

Virgin Stock	Any petroleum product or intermediate that was not produced by cracking or synthesis.
Visbreaking	A mild thermal cracking of very viscous material.
Viscosity	The ratio of shear stress to velocity gradient in laminar flow.

APPENDIX G

BIBLIOGRAPHY

APPENDIX G

BIBLIOGRAPHY

1. Bureau of Mines Mineral Industrial Survey.

2. United States Department of Commerce Census of Business.

3. API - United States Motor Gasoline Economics, Volume 1, pp. 2-10.

4. Paper presented to California Assembly Transportation Committee, Subcommittee on Air Pollution, W. Robert Epperly, Esso Research and Engineering Company.

5. Equations furnished by EPA from Bureau of Roads information.

6. *Oil and Gas Journal*, "Military Fuel Demand Turns Up Again," October 26, 1970, p. 44.

7. Aarlund, Leo R, *Oil and Gas Journal*, "Refiners Caught as Jet-Fuel Boom Looses Luster," November 11, 1970, pp. 97-100.

8. United States Department of Interior, Bureau of Mines, *Petroleum Statement Annual*, "Crude Petroleum, Petroleum Products, and Natural Gas Liquids," 1970.

9. Dosher, John R., "Trends in Petroleum Refining," *Chemical Engineering*, August 10, 1970, p. 102.

10. *Oil and Gas Journal*, "Jet Fuel to Hit 17.7 Billion Gallons by '81," May 25, 1970, p. 37.

11. *National Petroleum News*, Mid-May, 1970, pp. 76-97.

12. API, Department of Statistics, *Annual Statistical Review*, April, 1970.

13. *Oil and Gas Journal*, "IPAA Sees More of Same for '71," November 11, 1970, p. 46.

14. McCracken, Paul W. and Lincoln, George A., Statement on: "The Fuel Situation for the Winter of 1970-71," September 29, 1970.

15. *Oil and Gas Journal*, "Synthetic Rubber Feeds Seen Adequate," April 12, 1971, p. 40.

16. Struth, Dr. B. W., "Economics and Technology of Olefins," NPRA, March 21-23, 1971.

17. Collingswood, P., "World-Wide Developments in Olefin Supplies," joint meeting of Chemical Institute of Canada and ACS Division of Marketing and Economics, Toronto, May, 1970.

18. Ellis, I. T., "The Economic Outlook for 1970 and What It Will Mean for the World Petrochemical Industry," NPRA, San Antonio, Texas, April 5-7, 1971.

19. Mills, G. A. and Tosh, J. S., "Non-Energy Uses of Fuels," North American Fuel Technology Conference, Ottawa, May 31 - June 3, 1970.

20. Lewis, N. J., "The Critical Seventies: Petrochemicals Draw Heavily on LP Gases," API, Division of Refining, Houston, May 13, 1970.

21. Humble Oil and Refining Company as presented in *Chemical Engineering News*, March 8, 1971, p. 15.

22. Ockerbloom, N. E., "Outlook for Propylene in Western Europe, Japan, and the United States," European Chemical Association, Wiesbaden, Germany, September 22, 1969.

23. Loehmer, K. H. and Dodge, R. G., "World Aromatics Review and Forecast," presented at joint meeting of Chemical Institute of Canada and ACS Division of Marketing and Economics, Toronto, May, 1970.

24. Bregazzi, M., "The Canadian Petrochemical Market Picture," presented at joint meeting of Chemical Institute of Canada and ACS Division of Marketing and Economics, Toronto, May, 1970.

25. *Chemical Week*, "Aromatics: Output Up, Profits Down, Demand Soft," August 12, 1970, pp. 7-8.

26. Boulitrop, R., "The Petrochemical World of the 1980's," presented at joint meeting of Chemical Institute of Canada and ACS Division of Marketing and Economics, Toronto, May, 1970.

27. *Oil and Gas Journal*, February 8, 1971.

28. *API Petroleum Facts Figures - 1967.*

29. *Oil and Gas Journal*, April 6, 1970, pp. 115-144.

30. Campau, R. M., Ford Motor Company, "Low Emission Concept Vehicles," *Society of Automotive Engineers*, paper no. 710294, presented at the Automotive Engineering Congress, Detroit, Michigan, January 11-15, 1971.

31. Eccleston, B. H., and Hurn, R. W., "Comparative Emissions from Some Leaded and Prototype Lead-Free Automobile Fuels," United States Department of Interior, Bureau of Mines Publication, R.I. 7390, May, 1970.

AN ECONOMIC ANALYSIS
OF
PROPOSED SCHEDULES O & N
FOR
REMOVAL OF LEAD ADDITIVES FROM GASOLINE

25 June 1971

Prepared for the Environmental Protection Agency under Contract Number 68-02-0050

Bonner & Moore Associates, Inc.

500 Jefferson Bldg. | Cullen Center
Houston, Texas 77002 | (713) 228-0871
Cable: BONMOR

RGH-015 Addendum 1.

TABLE OF CONTENTS

Paragraph | Page

SECTION 1

INTRODUCTION

SECTION 2

RESULTS AND CONCLUSIONS

SECTION 3

DETAILS OF THE STUDY

LIST OF ILLUSTRATIONS

LIST OF TABLES

SECTION 1

INTRODUCTION

This addendum to "An Economic Analysis of Proposed Schedules for Removal of Lead Additives From Gasoline" (Report #RGH-015) describes the results of investigating two new schedules for removal of lead additives from gasoline. The new schedules were designed by the EPA to achieve reasonably rapid reduction of lead additive content in motor gasolines without the severe impact upon the Process Construction Industry indicated by preliminary results of the earlier study.

This investigation of the economic impact of the two new schedules involved the same mathematical models used in previous schedule analyses, and results are described in comparison to the same reference schedule. The reference schedule, modeling technique, and other study methodology are described in Section 5 of the original report.

SECTION 2

RESULTS AND CONCLUSIONS

Figure 2-1 compares the added investment required over the reference for the USA refineries for Schedules N, O, A, and L. This plot clearly illustrates the comparative severities of each of the schedules. Each of these schedules is within the capacity of the engineering and construction industry although Schedule L exhibits business cycle tendencies.

Characteristics of Schedules N and O are compared with those of Schedules A and L in Table 1.

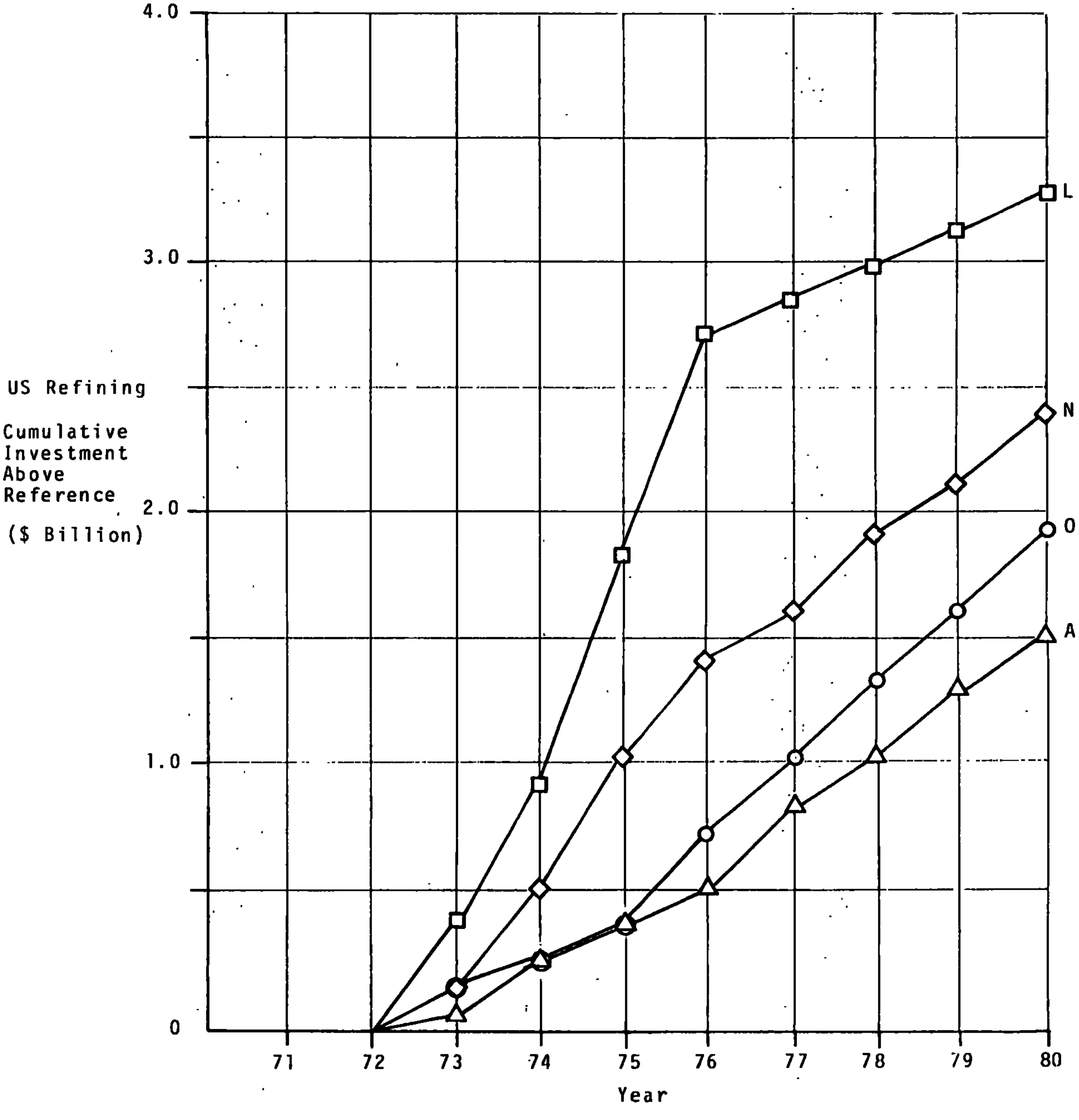


Figure 2-1. Cumulative Investment Requirements

TABLE 1

SUMMARY OF RESULTS, SCHEDULES N & O

Characteristics	Schedule	1971	1972	1973	1974	1975	1976	1980
		Schedule Year						
1. Added Yearly Investment (MM$ Above Reference[1,2]	A	15	-	42	187	122	172	1462
	O	-	134	256	221	389	218	2008
	N	-	817[3]	95	277	462	290	2474
	L	-	798[3]	344	412	825	844	3456
2. Total Added Cost (¢ Per Gallon)	A	0.16	0.20	0.23	0.22	0.22	0.21	0.21
	O	-	0 19	0.23	0.25	0.27	0.25	0.25
	N	-	0.32	0.34	0.41	0.52	0.48	0.36
	L	-	0.48	0.56	0.62	0.85	0.90	0.60
3. Per Cent Lead Reduction (Above 1971 Base)[4]	A	15	15	15	15	17	20	50
	O	0	21	33	45	59	63	77
	N	0	59	59	73	84	88	91
	L	-	64	73	82	93	100	100
4. Per Cent Crude Increase (Above Reference)	A	0.34	0.67	1.37	1.80	1.65	2.42	3.16
	O	-	0.27	0.96	1.41	1.26	1.79	3.02
	N	-	1.17	1.40	1.42	3.20	2.83	3.01
	L	-	1.77		2.76	-	5.03	3.29
5. Process Industry Construction Activity (% Increase Over Prior Year)	A	(4)	16	12	4	8	9	7
	O	(3)	17	10	8	8	7	7
	N	(3)	21	19	8	(1)	3	7
	L	1	28	18	14	(1)	(12)	7
6. Clear Pool Octane (RON)	A	88.5	87.7	87.5	87.7	88.3	88.5	90.4
	O	-	88.2	88.8	89.4	90.4	90.6	91.5
	N	-	91.1	90.8	91.7	92.8	92.6	92.6
	L	-	91.7	92.2	92.9	93.8	94.4	93.5
	Ref.	88.4	87.9	87.6	87.6	87.6	88.6	87.9
7. Per Cent Aromatics Pool	A	22	-	-	-	-	24	29
	O	-	22	23	24	26	27	30
	N	-	26	26	28	31	32	31
	L	-	27	28	32	36	38	36
	Ref.	23	22	21	21	21	22	22
93 RON Grade	A	18	-	-	-	-	32	34
	O	-	34	39	41	39	39	32
	N	-	32	32	41	28	39	29
	L	-	21	20	28	37	39	42
94 RON Grade	A	19	-	-	-	-	20	18
	O	-	22	21	21	19	16	21
	N	-	25	26	24	31	23	38
	L	-	24	28	29	36	35	21
	Ref.	23	22	21	21	21	21	21
100	A	32	-	-	-	-	12	13
	O	-	15	15	14	18	23	47
	N	-	28	21	27	37	40	39
	L	-	39	37	45	38	53	33
	Ref.	22	24	21	22	21	22	24

[1]Excluding Cost for Distribution
[2]1980 Figures are Cumulative
[3]Includes 1971 Investment
[4]Calculated on 1971 Base whereas Previous Summary was calculated on 1970 Base.

SECTION 3

DETAILS OF THE STUDY

3.1 SCHEDULE O

3.1.1 Description of Schedule

Lead removal Schedule O is for a three-grade marketing environment in which the lowest octane grade (93.0 RON) is permitted to have 0.5 gm/gallon until 1974, at which time all lead is removed from it. The two grades corresponding to current regular and premium gasolines are permitted to contain equal lead levels throughout the schedule. The lead levels are shown below in paragraph 3.1.5.

3.1.2 Reason for Selecting Schedule O for Study

Schedule O was designed to remove approximately 60 percent of the current lead additives without inducing a business cycle in the construction industry. The scheduled lead removal rate over the current national consumption is shown below.

Year	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
% Removal Over 1970-71 Usage*	0	21	33	45	59	63	68	71	74	77

*Average lead level used for base years 1970-71, was 2.4 gm/gallon

3.1.3 Raw Stock Effects

The comparison of raw stock requirements for Schedule O to raw stock requirements for the Reference Schedule is shown in Table 2. Since Schedule O is relatively mild in the early years, its raw stock requirements are similar to Schedule A.

3.1.4 By-Product Effects

Table 3 shows the production of variable by-products. These are shown with the Reference Schedule for comparison.

TABLE 2

RAW STOCK REQUIREMENTS FOR SCHEDULE 0

(Millions of Barrels/Year)

	1972		1973		1974		1975		1976		1980	
	Schedule		Schedule		Schedule		Schedule		Schedule		Schedule	
	0	Ref.	0	Ref.	0	Ref.	0	Ref.	0	Ref.	0	Ref.
Normal Butane	76.8	69.8	72.7	82.9	67.2	81.6	81.7	78.5	85.8	79.8	92.7	79.8
Iso-Butane	55.3	50.2	52.4	59.7	48.4	58.7	58.8	56.5	61.8	57.3	66.8	57.4
Natural Gasoline	192.9	192.9	192.9	192.9	192.9	192.9	192.9	192.9	192.9	192.9	192.9	192.9
Subtotal	325.0	312.9	318.0	335.5	308.5	333.2	333.4	327.9	340.5	330.0	352.4	330.1
Crude Oil	4565.9	4553.7	4786.2	4740.6	5024.3	4954.4	5247.1	5182.0	5514.2	5417.3	6754.9	6557.1
TOTAL	4890.9	4866.6	5104.2	5076.1	5332.8	5287.6	5580.5	5509.9	5854.7	5747.3	7107.3	6887.2
% Increase in Crude	0.27		0.96		1.41		1.26		1.79		3.02	

TABLE 3

BY-PRODUCT PRODUCTION FOR SCHEDULE O

	1972 Schedule		1973 Schedule		1974 Schedule		1975 Schedule		1976 Schedule		1980 Schedule	
	O	Reference	O	Reference	O	Reference	O	Reference	O	Reference	O	Reference
Coke, MM Tons/Yr.	15.7	15.8	17.7	17.5	19.9	19.5	21.9	21.6	24.4	23.8	37.2	36.1
Fuel Gas, 10^{12} BTU/Yr.	1222	1268	1295	1292	1391	1360	1404	1443	1499	1528	2020	2070

3.1.5 Motor Gasoline Blending

Schedule 0 was designed to remove approximately 60 percent of the 1970-1971 lead usage by 1975. This is achieved by scheduling the lead levels of the three grades as illustrated in Table 4. Table 5 shows the characteristics and compositions of the three grades as well as composition of a composited pool of the three grades.

TABLE 4

TEL CONTENTS OF SCHEDULE 0 GASOLINES

(gm/gal)

Grade	1972	1973	1974	1975	1976	1977	1978	1979	1980
93	0.50	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00
94	2.00	1.70	1.50	1.25	1.25	1.25	1.25	1.25	1.25
100	2.00	1.70	1.50	1.25	1.25	1.25	1.25	1.25	1.25
Pool	1.81	1.49	1.17	0.84	0.72	0.61	0.53	0.45	0.39

TABLE 5

GASOLINE SUMMARY FOR SCHEDULE 0
(Sheet 1 of 2)

	1972	1973	1974	1975	1976	1980
93 Octane Blend:						
Volume, 10^9 Gals/Yr.	11.9	17.4	22.4	35.3	47.4	88.4
TEL, gm/gal	0.5	0.5	0.0	0.0	0.0	0.0
Leaded RON	93.0	93.0	-	-	-	-
Leaded MON	85.0	85.0	-	-	-	-
Clear RON	91.3	91.5	93.0	93.0	93.0	93.0
Clear MON	82.2	81.8	85.0	85.0	85.0	85.0
Stream Composition, %						
Cracked Stocks	33	19	-	-	1	17
Alkylate Products	5	-	6	8	9	17
Aromatic Based	36	53	62	61	60	40
Light Iso-Paraffins	10	13	17	14	12	8
Paraffinic Stocks	10	6	15	17	18	17
Miscellaneous	6	9	-	-	-	1
Hydrocarbon Composition, %						
Paraffins	43	46	56	57	56	54
Olefins	16	11	-	-	-	8
Naphthenes	7	5	3	4	5	6
Aromatics	34	39	41	39	39	32
94 Octane Blend:						
Volume, 10^9 Gals/Yr.	57.5	59.2	60.8	55.6	50.9	35.9
TEL, gm/gal	2.0	1.7	1.50	1.25	1.25	1.25
Leaded RON	94.0	94.0	94.0	94.0	94.0	94.0
Leaded MON	86.0	86.0	86.0	86.0	86.0	86.0
Clear RON	85.7	86.3	86.9	87.6	87.5	87.7
Clear MON	77.5	78.1	78.5	79.2	79.2	79.1
Stream Composition, %						
Cracked Stocks	43	46	45	51	57	49
Alkylate Products	-	3	5	9	12	5
Aromatic Based	27	23	24	17	7	18
Light Iso-Paraffins	-	-	-	-	-	-
Paraffinic Stocks	28	28	25	23	24	28
Miscellaneous	2	-	1	-	-	-
Hydrocarbon Composition, %						
Paraffins	45	46	48	49	49	49
Olefins	19	19	19	21	24	21
Naphthanes	14	14	12	11	11	9
Aromatics	22	21	21	19	16	21

TABLE 5

GASOLINE SUMMARY FOR SCHEDULE O

(Sheet 2 of 2)

	1972	1973	1974	1975	1976	1980
100 Octane Blend:						
Volume, 10^9 Gals/Yr.	26.0	22.4	19.3	16.2	13.4	4.1
TEL, gm/gal	2.00	1.70	1.50	1.25	1.25	1.25
Leaded RON	100.0	100.0	100.0	100	100	100.0
Leaded MON	94.5	95.4	92.7	92.1	92	92.0
Clear RON	93.0	93.4	94.1	94.9	94.8	94.7
Clear MON	85.1	86.6	85.5	85.8	85.3	85.0
Stream Composition, %						
Cracked Stocks	9	-	24	23	20	-
Alkylate Products	48	52	45	40	34	9
Aromatic Based	23	24	15	19	24	64
Light Iso-Paraffins	6	7	3	5	5	-
Paraffinic Stocks	14	17	12	9	12	27
Miscellaneous	-	-	1	4	5	-
Hydrocarbon Composition, %						
Paraffins	76	80	69	65	65	53
Olefins	4	-	10	11	9	-
Naphthanes	5	5	7	6	3	-
Aromatics	15	15	14	18	23	47
Pool:						
Stream Composition, %						
Cracked Stocks	34	33	32	30	29	26
Alkylate Products	11	11	11	13	13	13
Aromatic Based	27	29	31	32	31	34
Light Iso-Paraffins	3	3	4	5	6	6
Paraffinic Stocks	23	22	21	19	20	20
Miscellaneous	2	2	1	1	1	1
Hydrocarbon Composition, %						
Paraffins	52	53	53	53	54	53
Olefins	15	14	13	13	12	11
Naphthanes	11	10	10	8	7	7
Aromatics	22	23	24	26	27	30
RON, CL	88.2	88.8	89.4	90.4	90.6	91.5
MON, CL	80.1	80.6	81.1	82.0	82.4	83.3

3.1.6 Process Capacity Changes

The capacities of the major processes required for Schedule O are shown in Table 6.

TABLE 6

PROCESS CAPACITY GROWTH FOR SCHEDULE O

(Millions of Barrels/Day)

	1972	1973	1974	1975	1976	1980
Crude Distillation	12.5	13.1	13.9	14.5	15.2	18.6
Coking	1.0	1.1	1.3	1.4	1.6	2.4
Cat Cracking	3.6	3.6	3.6	3.6	3.6	3.6
Hydrocracking	0.5	0.7	0.8	1.1	1.2	1.4
Cat Reforming	2.3	2.6	2.9	3.1	3.3	4.1
Alkylation	0.8	0.9	0.9	1.0	1.1	1.2
Extraction	0.4	0.6	0.7	0.9	1.1	1.7
Isomerization	0.1	0.1	0.1	0.2	0.2	0.2

3.1.7 Cost Effects

Table 7 shows the cost differences between the Reference Schedule and Schedule O. These costs, shown as ¢/gallon and as total annual costs, are broken down into refinery capital investment cost, other refinery costs, and the cost of three grade distribution.

TABLE 7

COST EFFECTS OF SCHEDULE 0

	1972	1973	1974	1975	1976	1977	1978	1979	1980
National Added Costs, MM$/Yr.									
Refining Investment Costs	35	102	160	262	319	371	423	474	526
Other Refining Costs	(110)	(213)	(244)	(316)	(380)	(433)	(484)	(519)	(546)
Total Added Refining Costs	(75)	(111)	(84)	(54)	(61)	(62)	(61)	(45)	(20)
Added Distribution Costs	255	340	340	340	340	340	340	340	340
Total Added Costs	180	229	256	286	279	278	279	295	320
National Added Costs, ¢/Gal*									
Refining Investment Costs	0.04	0.11	0.15	0.25	0.29	0.32	0.35	0.38	0.41
Other Refining Costs	(0.13)	(0.22)	(0.23)	(0.30)	(0.34)	(0.37)	(0.40)	(0.41)	(0.42)
Total Added Refining Costs	(0.09)	(0.11)	(0.08)	(0.05)	(0.05)	(0.05)	(0.05)	(0.03)	(0.01)
Added Distribution Costs	0.28	0.34	0.33	0.32	0.30	0.29	0.28	0.27	0.26
Total Added Costs	0.19	0.23	0.25	0.27	0.25	0.24	0.23	0.24	0.25

*Using total gasoline demand as a divisor.

3.2 SCHEDULE N

3.2.1 Description of Schedule

Lead removal Schedule N is for a three-grade marketing environment in which the lowest octane grade (93.0 RON) is permitted to have .5 gm/gallon until 1974, at which time all lead is removed from it. The two grades corresponding to current regular and premium gasolines are permitted to contain equal lead levels throughout the schedule. For the years 1972-1974, the lead level was determined by the construction limit, and for 1975-1980 the level was set at 0.5 gm. The calculated lead levels are shown in paragraph 3.2.5.

3.2.2 Reason for Selecting Schedule N for Study

Schedule N was selected to determine the earliest economically feasible year for setting the lead level at 0.5 gms for current premium and regular grade gasolines. The term "economically feasible" is defined as not exceeding the construction industry growth capacity (see RGH-015, Section 5), and further, as not inducing a business cycle in this industry. Percent removal over current usage is shown below.

Year	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
% Removal Over 1970-71 Usage*	0	59	59	73	84	87	88	89	90	91

*Usage based on average 2.4 gm/gal lead level of average motor gasoline.

3.2.3 Raw Stock Effects

Table 8 shows the raw stock usage of Schedule N. Although Schedule N is more severe than Schedule O in removal of lead, the raw material requirements do not significantly vary until the peak years of 1975 and 1976, and by 1980 the raw material requirements are essentially the same as those shown for Schedule O. These schedules fall between Schedules A and L (both three-grade schedules) in crude requirements for the peak years. By 1980 all three-grade schedules demand about the same amount of additional crude due to the (predominant) percentage of unleaded 93 octane motor gasoline.

TABLE 8

RAW STOCK REQUIREMENTS FOR SCHEDULE N

(Millions of Barrels/Year)

	1972		1973		1974		1975		1976		1980	
	Schedule		Schedule		Schedule		Schedule		Schedule		Schedule	
	N	Ref.	N	Ref.	N	Ref.	N	Ref.	N	Ref.	N	Ref.
Normal Butane	51.3	69.8	56.8	82.9	67.6	81.6	49.7	78.5	69.1	79.8	92.7	79.8
Iso-Butane	37.0	50.2	40.9	59.7	49.5	58.7	35.9	56.6	49.7	57.3	66.8	57.4
Natural Gasoline	192.9	192.9	192.9	192.9	192.9	192.9	181.4	192.9	192.9	192.9	192.9	192.9
Subtotal	281.2	312.9	290.6	335.5	310.0	333.2	267.0	327.9	311.7	330.0	352.4	330.1
Crude Oil	4607.0	4553.7	4806.9	4740.6	5025.0	4954.4	5348.0	5182.0	5570.8	5417.3	6754.6	6557.1
TOTAL	4888.2	4866.6	5097.5	5076.1	5335.0	5287.6	5615.0	5509.9	5882.5	5747.3	7107.0	6887.2
% Increase in Crude	1.17		1.40		1.42		3.20		2.83		3.01	

3.2.4 By-Product Effects

Schedule N falls approximately midway between A and L in severity of processing as indicated by the by-product fuel gas production for 1976 (see Table 9). Fuel gas production indicates that Schedule N requires more cracking capacity than Schedule O for all years since it removes lead at a faster rate. Coke production is more closely related to the volume of crude runs. Therefore, as in the raw material effects, coke make does not significantly vary except in the peak 1974 and 1976 years.

TABLE 9

BY-PRODUCT PRODUCTION FOR SCHEDULE N

	1972 Schedule		1973 Schedule		1974 Schedule		1975 Schedule		1976 Schedule		1980 Schedule	
	N	Reference	N	Reference	N	Reference	N	Reference	N	Reference	N	Reference
Coke, MM Tons/Yr.	15.5	15.8	17.4	17.5	19.3	19.5	22.3	21.6	24.7	23.8	37.1	36.1
Fuel Gas, 10^{12} BTU/Yr.	1320	1268	1344	1292	1422	1360	1634	1443	1691	1528	2033	2070

3.2.5 Motor Gasoline Blending

A review of the average aromatic contents of the composite pool for Schedules A, O, N, and L for the year 1976 is shown in Table 10. The average lead level of the pool shows clearly the inverse relationship of aromatic content to lead level at a given pool octane requirement. Table 11 shows the maximum lead levels set for the three grades to meet the objectives of the schedule. Table 12 shows the characteristics and composition of each of the three gasoline grades as well as the properties of the composite pool. A comparison with the table for Schedule O indicates Schedule N is more severe, requiring more aromatics to make motor gasoline.

TABLE 10

AROMATICS AND LEAD LEVELS

	SCHEDULE			
	A	O	N	L
1976 Pool Aromatic Content, %	24	27	32	38
1976 Avg lead Content, gm/gal	1.56	0.72	0.29	0.0

TABLE 11

TEL CONTENTS OF SCHEDULE N GASOLINES

(gm/gal)

Grade	1972	1973	1974	1975	1976	1977	1978	1979	1980
93	0.50	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.0
94	1.00	1.00	0.75	0.50	0.50	0.50	0.50	0.50	0.50
100	1.00	1.00	0.75	0.50	0.50	0.50	0.50	0.50	0.50
Pool	0.94	0.91	0.59	0.34	0.29	0.25	0.21	0.18	0.15

TABLE 12

GASOLINE SUMMARY FOR SCHEDULE N

(Sheet 1 of 2)

	1972	1973	1974	1975	1976	1980
93 Octane Blend:						
Volume, 10^9 Gals/Yr.	11.9	17.4	22.4	35.3	47.4	88.4
TEL, gm/gal	0.50	0.50	0.0	0.0	0.0	-
Leaded RON	93.0	93.0	-	-	-	-
Leaded MON	85.0	85.0	-	-	-	-
Clear RON	91.1	91.1	93.0	93.0	93.0	93.0
Clear MON	81.8	82.0	85.0	85.0	85.0	85.0
Stream Composition, %						
Cracked Stocks	33	36	19	32	19	29
Alkylate Products	-	-	3	17	6	19
Aromatic Based	38	36	44	22	41	27
Light Iso-Paraffins	18	17	16	15	13	9
Paraffinic Stocks	5	6	18	13	20	15
Miscellaneous	6	5	-	1	1	1
Hydrocarbon Composition, %						
Paraffins	46	44	46	52	47	52
Olefins	16	17	8	14	8	12
Naphthanes	6	7	5	6	6	7
Aromatics	32	32	41	28	39	29
94 Octane Blend:						
Volume, 10^9 Gals/Yr.	57.5	59.2	60.8	55.6	50.9	35.9
TEL, gm/gal	1.00	1.00	0.75	0.50	0.50	0.50
Leaded RON	94.0	94.0	94.0	94.0	94.0	94.0
Leaded MON	86.0	86.0	86.0	86.0	86.0	86.0
Clear RON	88.8	88.9	89.7	91.2	91.0	91.2
Clear MON	79.7	79.8	80.5	81.5	82.0	81.5
Stream Composition, %						
Cracked Stocks	43	41	41	36	45	21
Alkylate Products	6	5	11	7	16	-
Aromatic Based	27	30	26	35	19	54
Light Iso-Paraffins	-	1	1	-	2	-
Paraffinic Stocks	24	23	20	21	18	25
Miscellaneous	-	-	1	-	-	-
Hydrocarbon Composition, %						
Paraffins	49	49	52	48	51	50
Olefins	18	17	17	15	19	9
Naphthanes	8	8	7	6	7	3
Aromatics	25	26	24	31	23	38

TABLE 12

GASOLINE SUMMARY FOR SCHEDULE N
(Sheet 2 of 2)

	1972	1973	1974	1975	1976	1980
100 Octane Blend:						
Volume, 10^9 Gals/Yr.	26.0	22.4	19.3	16.2	13.4	4.1
TEL, gm/gal	1.00	1.00	0.75	0.50	0.50	0.50
Leaded RON	100.0	100.0	100.0	100.0	100.0	100.0
Leaded MON	92.9	94.3	92.0	92.0	92.0	92.0
Clear RON	96.6	95.8	96.9	98.3	97.4	97.7
Clear MON	86.9	88.1	87.2	87.8	88.6	87.8
Stream Composition, %						
Cracked Stocks	8	-	12	-	-	-
Alkylate Products	34	46	32	22	25	20
Aromatic Based	38	29	38	58	56	57
Light Iso-Paraffins	14	12	11	13	-	15
Paraffinic Stocks	6	13	7	6	19	8
Miscellaneous	-	-	-	1	-	-
Hydrocarbon Composition, %						
Paraffins	66	75	63	58	53	57
Olefins	3	-	5	-	-	-
Naphthanes	3	4	5	5	7	4
Aromatics	28	21	27	37	40	39
Pool:						
Stream Composition, %						
Cracked Stocks	34	33	32	30	29	26
Alkylate Products	12	12	12	12	13	13
Aromatic Based	31	31	32	34	32	35
Light Iso-Paraffins	5	5	6	7	6	7
Paraffinic Stocks	17	18	17	16	19	18
Miscellaneous	1	1	1	1	1	1
Hydrocarbon Composition, %						
Paraffins	53	53	53	50	49	52
Olefins	15	14	13	13	12	11
Naphthanes	6	7	6	6	7	6
Aromatics	26	26	28	31	32	31
RON Clear	91.1	90.8	91.7	92.8	92.6	92.6
RON Clear	81.8	81.9	82.7	83.6	84.0	84.1

3.2.6 Process Capacity Changes

Table 13 shows the in-plant capacity requirements for the major processes. No over building or excess capacity over the normal service factor is reflected in the figures. These figures represent the normal fresh feed throughputs for all but alkylation and extraction, which are in terms of product. A review of the numbers again illustrates that Schedule N is more severe than Schedule O and less severe than Schedule L. As an example, in 1976 Schedule A required 3.0 of reformer capacity compared with 3.3 for Schedule O, 3.6 for Schedule N, and 4.1 for Schedule L.

TABLE 13

PROCESS CAPACITY GROWTH FOR SCHEDULE N
(Millions of Barrels/Day)

	1972	1973	1974	1975	1976	1980
Crude Distillation	13.0	13.4	14.1	15.0	15.4	19.3
Coking	1.0	1.1	1.2	1.4	1.6	2.4
Cat Cracking	3.6	3.6	3.6	3.6	3.6	3.6
Hydrocracking	0.8	0.9	0.9	1.1	1.3	1.5
Cat Reforming	2.8	2.9	3.1	3.6	3.6	4.3
Alkylation	0.8	0.9	1.0	1.0	1.1	1.3
Extraction	0.5	0.7	0.9	0.9	1.6	2.0
Isomerization	0.2	0.2	0.2	0.2	0.2	0.3

3.2.7 Cost Effects

Table 14 shows the annual cost for Schedule N relative to the Reference Schedule. These costs are broken down into refinery investment costs, other refining costs, and added distribution costs for the three-grade system. The costs are shown in millions of dollars per year and in cents per gallon, using the total gallonage of Schedule N for each year.

TABLE 14

COST EFFECTS OF SCHEDULE N

	1972	1973	1974	1975	1976	1977	1978	1979	1980
National Added Costs, MM$/Yr.									
Refining Investment Costs	214	239	312	433	509	530	565	600	648
Other Refining Costs	(159)	(245)	(234)	(218)	(316)	(379)	(524)	(484)	(521)
Total Added Refining Costs	55	6	78	215	193	151	41	116	127
Added Distribution Costs	255	340	340	340	340	340	340	340	340
Total Added Costs	310	334	418	555	533	491	381	456	467
National Added Cost, ¢/Gal*									
Refining Investment Costs	0.22	0.24	0.30	0.41	0.46	0.46	0.47	0.48	0.50
Other Refining Costs	(0.18)	(0.24)	(0.22)	(0.21)	(0.28)	(0.33)	(0.43)	(0.38)	(0.40)
Total Added Refining Costs	0.04	0.00	0.08	0.20	0.18	0.13	0.04	0.10	0.10
Added Distribution Costs	0.28	0.34	0.33	0.32	0.30	0.29	0.28	0.27	0.26
Total Added Costs	0.32	0.34	0.41	0.52	0.48	0.42	0.32	0.37	0.36

*Using Schedule N's total gasoline as a divisor.

3.3 IMPACT ON THE CONSTRUCTION INDUSTRY

The impact of Schedules O and N upon the construction industry was studied by scaling the investments required in the individual refinery models to a national level. The methods used to carry out this scaling and to make adjustments for obsolescence and replacements are described in Section 5 of report #RGH-015.

Table 15 shows the investments being completed by the construction industry in each year of Schedules O and N. That is, the facilities represented by these investments are operable for the first time in the year for which the investment is recorded.

It should be noted that all investments shown in these tables other than U.S. and Canadian refining are the same for all schedules. Also, U.S. refining investments for the years 1970, 1971, and 1972 are constant for each schedule. The refinery investments for these years were based upon data reported in the Oil and Gas Journal and reported levels of engineering and construction backlog.

Schedule O did not require as much investment in these early years as shown on Table 15, indicating that the industry should be capable of meeting this schedule in the early years without too much difficulty. The implied excess capacity was distributed over the years 1973, 1974, and 1975 in the same ratio as the model year results for the same period.

Figures 3-1 and 3-2 plot these refinery investments together with the forecasted maximum construction industry capacity available to refining.

Table 16 gives a breakdown of the construction dollar according to the various sectors of the construction industry for each schedule. This breakdown includes a distribution of the total investment dollars backward in time to reflect the fact that engineering must start well ahead of materials ordering, etc. For convenience in observing the effect of the various schedules so far as producing boom or bust conditions is concerned, the lower half of these tables describes the changes in construction activity from year to year.

TABLE 15

CONSTRUCTION INDUSTRY INVESTMENTS

SCHEDULE O

INVESTMENT SUMMARY - MM$/YEAR

	PETROCHEMICAL			REFINING				TOTAL		
	FOREIGN	US/CANADA	TOTAL	FOREIGN	CANADA	US	TOTAL	FOREIGN	US/CANADA	TOTAL
1970	100	1,200	1,300	105	115	1,050	1,270	205	2,365	2,570
1971	110	1,330	1,440	125	127	1,158	1,411	235	2,616	2,851
1972	120	1,500	1,620	140	70	635	845	260	2,205	2,465
1973	135	1,680	1,815	150	110	1,004	1,265	285	2,795	3,080
1974	150	1,880	2,030	160	117	1,064	1,341	310	3,061	3,371
1975	165	2,020	2,185	170	128	1,162	1,460	335	3,310	3,645
1976	185	2,220	2,405	180	132	1,204	1,516	365	3,556	3,921
1977	205	2,440	2,645	185	137	1,245	1,567	390	3,822	4,212
1978	230	2,690	2,920	190	139	1,262	1,590	420	4,090	4,510
1979	250	2,960	3,210	195	141	1,278	1,614	445	4,379	4,824
1980	280	3,250	3,530	200	142	1,294	1,637	480	4,687	5,167
1981	310	3,580	3,890	205	144	1,311	1,660	515	5,035	5,550
1982	345	3,930	4,275	210	146	1,327	1,683	555	5,403	5,958
TOTALS	2,585	30,680	33,265	2,215	1,649	14,994	18,858	4,800	47,323	52,123

SCHEDULE N

INVESTMENT SUMMARY - MM$/YEAR

	PETROCHEMICAL			REFINING				TOTAL		
	FOREIGN	US/CANADA	TOTAL	FOREIGN	CANADA	US	TOTAL	FOREIGN	US/CANADA	TOTAL
1970	100	1,200	1,300	105	115	1,050	1,270	205	2,365	2,570
1971	110	1,330	1,440	125	127	1,158	1,411	235	2,616	2,851
1972	120	1,500	1,620	140	70	635	845	260	2,205	2,465
1973	135	1,680	1,815	150	114	1,036	1,300	285	2,830	3,115
1974	150	1,880	2,030	160	156	1,417	1,733	310	3,453	3,763
1975	165	2,020	2,185	170	179	1,625	1,974	335	3,824	4,159
1976	185	2,220	2,405	180	145	1,315	1,640	365	3,680	4,045
1977	205	2,440	2,645	185	129	1,173	1,487	390	3,742	4,132
1978	230	2,690	2,920	190	131	1,188	1,509	420	4,009	4,429
1979	250	2,960	3,210	195	132	1,203	1,530	445	4,295	4,740
1980	280	3,250	3,530	200	134	1,217	1,551	480	4,601	5,081
1981	310	3,580	3,890	205	136	1,232	1,572	515	4,947	5,462
1982	345	3,930	4,275	210	137	1,247	1,594	555	5,314	5,869
TOTALS	2,585	30,680	33,265	2,215	1,705	15,497	19,416	4,800	47,881	52,681

o - U.S. Refinery Investment

62 - 70 Reported
71 - 72 Projected
73 - 80 Limited by Construction

¤ - Schedule 0

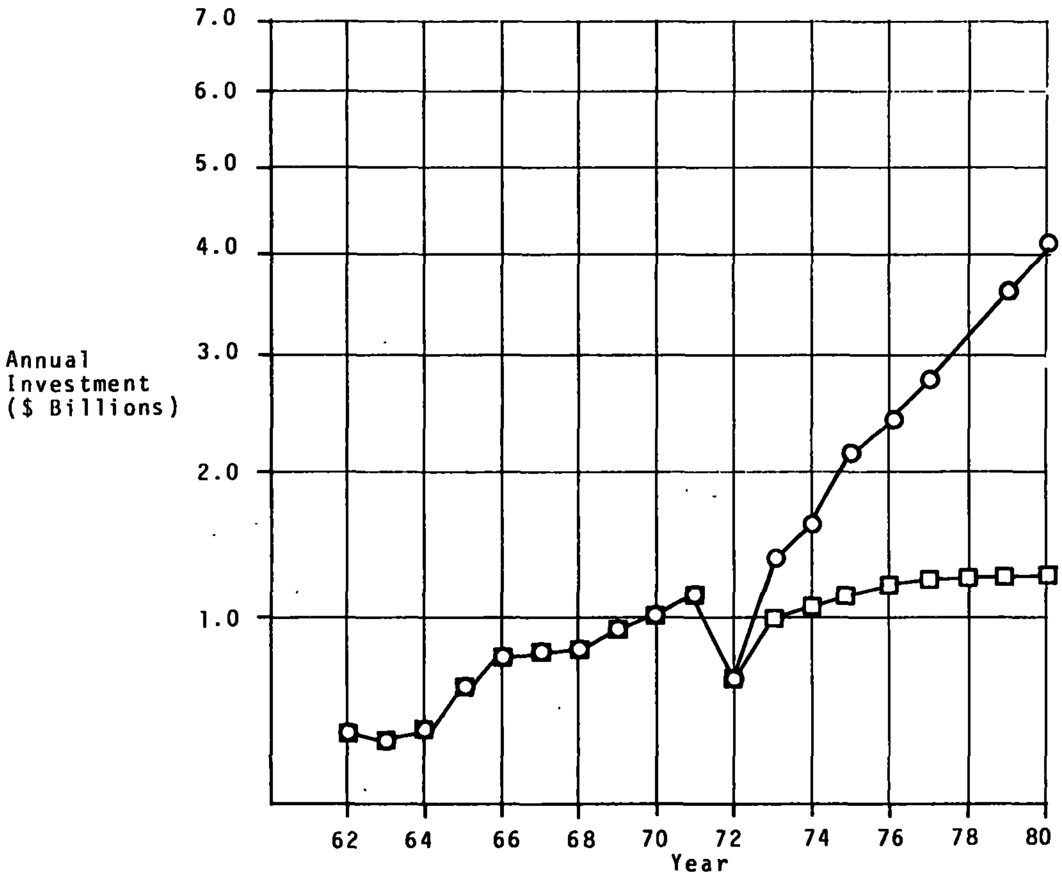


Figure 3-1. Refinery Investment Required by Schedule 0

O - U.S. Refinery Investment

62 - 70 Reported
71 - 72 Projected
73 - 80 Limited by Construction

□ - Schedule N

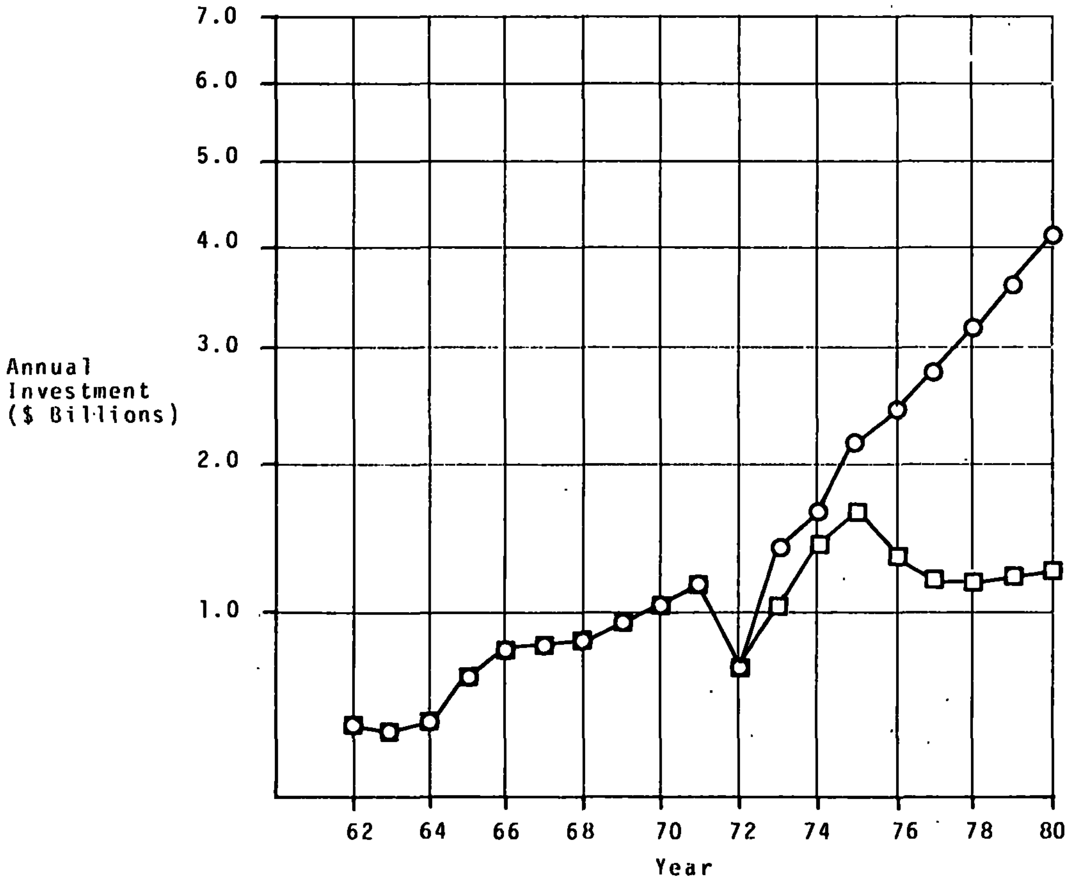


Figure 3-2. Refinery Investment Required by Schedule N

TABLE 16

CONSTRUCTION COSTS BY SECTOR

SCHEDULE N

TOTAL US & FOREIGN - MM$/YR

	ENGINEERING	MATERIALS	FIELD LABOR	FEES & MISC	
1971	360	1,240	478	441	2,518
1972	439	1,544	546	526	3,055
1973	508	1,815	672	629	3,624
1974	532	1,918	760	688	3,898
1975	531	1,889	762	685	3,868
1976	554	1,956	765	701	3,975
1977	592	2,093	808	746	4,239
1978	634	2,242	865	799	4,541
1979	681	2,406	927	856	4,870
1980	731	2,585	996	920	5,233
TOTALS	5,562	19,688	7,579	6,991	39,821

NET CHANGE AS PERCENT OF PRIOR YEAR

1971	4	-2	-8	-5	-3
1972	22	25	14	19	21
1973	16	18	23	20	19
1974	5	6	13	9	8
1975	-0	-2	0	-0	-1
1976	4	4	0	2	3
1977	7	7	6	6	7
1978	7	7	7	7	7
1979	7	7	7	7	7
1980	7	7	7	7	7

SCHEDULE O

TOTAL US & FOREIGN - MM$/YR

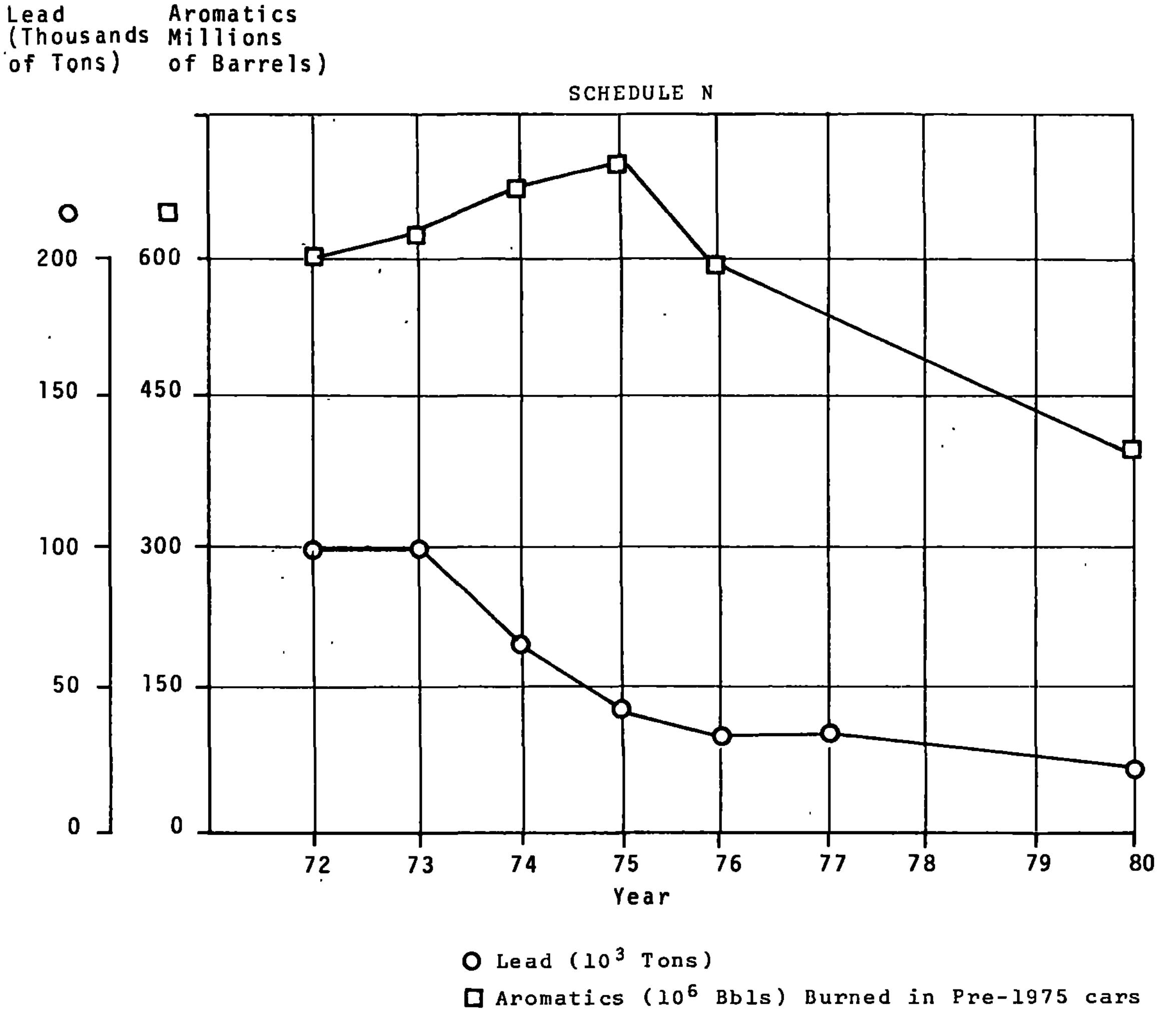
	ENGINEERING	MATERIALS	FIELD LABOR	FEES & MISC	
1971	358	1,234	478	440	2,509
1972	414	1,466	540	511	2,931
1973	452	1,602	613	567	3,235
1974	488	1,729	665	614	3,496
1975	525	1,858	716	661	3,760
1976	563	1,994	769	709	4,036
1977	603	2,134	824	760	4,321
1978	645	2,284	882	813	4,624
1979	692	2,449	944	871	4,956
1980	743	2,629	1,013	935	5,321
TOTALS	5,482	19,379	7,445	6,881	39,188

NET CHANGE AS PERCENT OF PRIOR YEAR

1971	3	-2	-8	-5	-3
1972	16	19	13	16	17
1973	9	9	13	11	10
1974	8	8	8	8	8
1975	8	7	8	8	8
1976	7	7	7	7	7
1977	7	7	7	7	7
1978	7	7	7	7	7
1979	7	7	7	7	7
1980	7	7	7	7	7

3.4 IMPACT OF SCHEDULES O AND N UPON REACTIVE EMISSIONS

Figure 3-3 shows the estimated lead usage and aromatics burned in pre-1975 cars for years 1972 through 1980 on Schedules N and O. Schedule N has a lower lead usage than Schedule O and consequently has a higher aromatic usage in pre-1975 cars.



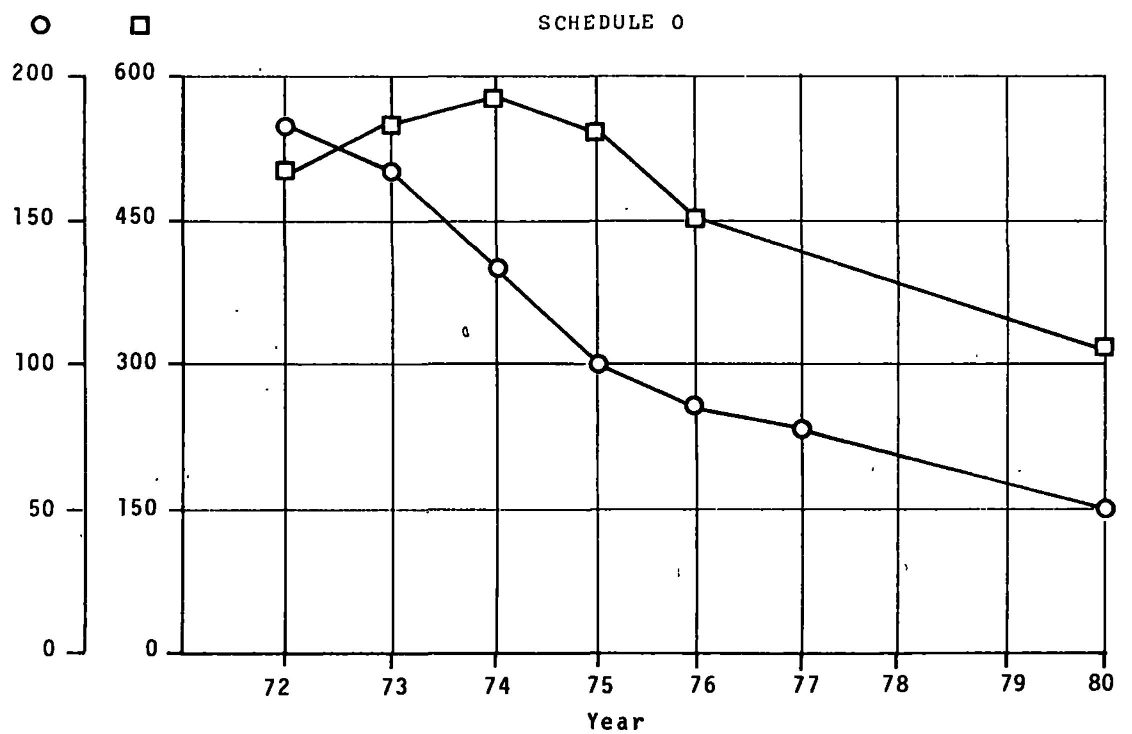


Figure 3-3. Lead and Aromatics Levels for Schedules N and O