STAFF REPORT

SUPPLY AND COST OF ALTERNATIVES TO MTBE IN GASOLINE

TECHNICAL APPENDICES

Technical Documents

DECEMBER 1998

CALIFORNIA ENERGY COMMISSION

Pete Wilson, ***Governor***

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Technical Documents

Prepared For:

ACUREX ENVIRONMENTAL CORPORATION
AND
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Prepared By:

PURVIN & GERTZ, INC.

Dallas - Houston - Los Angeles
Calgary - London
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John H. Vautrain

1.0 Introduction

1.1 Parties

Purvin & Gertz, Inc., (Purvin & Gertz), was retained by Acurex Environmental Corporation (Acurex) on behalf of the California Energy Commission (CEC) to provide evaluations and assistance related to the proposed MTBE ban in California. Purvin & Gertz was retained to provide four deliverables: a presentation at a public workshop, a report on the supply costs of CARB gasoline and blend stocks from outside California, a report on the marine terminal infrastructure and associated limitations, and compilation of the final report combining Purvin & Gertz work with that of other consultants. This document is the compilation of the final report of all the consultants.

This report has been prepared for the sole benefit of the CEC. Any third party in possession of the report may not rely upon its conclusions without the written consent of Purvin & Gertz. Purvin & Gertz conducted this analysis and prepared this report utilizing reasonable care and skill in applying methods of analysis consistent with normal industry practice. All results are based on information available at the time of review. Changes in factors upon which the review is based could affect the results. Forecasts are inherently uncertain because of events or combinations of events which cannot reasonably be foreseen including the actions of government, individuals, third parties and competitors. ***NO IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE SHALL APPLY.***

Some of the information on which this report is based has been provided by others. Purvin & Gertz has utilized such information without verification unless specifically noted otherwise. Purvin & Gertz accepts no liability for errors or inaccuracies in information provided by others.
Two other consultants, Mathpro, Inc. (Mathpro) and Energy Security Analysis, Inc. (ESAI) have prepared reports on other aspects of the MTBE ban under separate contracts with Acurex which are attached to this summary. Although the goals of the work are joint, the three consultants, Purvin & Gertz, Mathpro and ESAI, are working independently and none is responsible for the work or results of another. Neither Mathpro nor ESAI is responsible for any results or opinions presented in this summary.

2.0 Summary

Three consultants have worked individually with the direction and assistance of CEC staff to prepare extensive studies of various aspects of a impacts of an MTBE ban. This summary is attached to appendices comprised of all the final reports of all the consultants. Reference is made to an Executive Summary and a Key Findings document prepared by CEC staff which presents legislative background and the design of the study as devised by CEC.

The first section of this report describes the answers sought and how the consultant reports fit together to provide the answers. None of the work of the various consultants is duplicative and all work together to provide the information required by CEC.

The ESAI report is the logical starting point of the analysis. This report reviews the alternatives to MTBE. There are other chemicals that could be used by the refining industry in lieu of MTBE to provide oxygen content in gasoline as required by regulation. ESAI has determined how much of each of the alternatives is potentially available. ESAI has also determined the cost of accessing each increment of supply of each of the alternatives.

The Purvin & Gertz reports describe the availability of CARB reformulated fuel from refineries outside California and the adequacy of the infrastructure to deliver it to the state. The cost of external supplies was determined for each major source region. Furthermore, Purvin & Gertz has provided a common pricing structure for use in all the analyses. Using a common pricing structure ensured that the results of the individual reports could be melded together.

The Mathpro reports used as inputs the Purvin & Gertz and ESAI report results. Mathpro developed a sophisticated mathematical model of the California refining industry. That model was perfected using aggregated data from the refiners that had been provided to CEC under PIIRA procedures. Then Mathpro used the mathematical model to identify all the cost elements of many alternative methods of banning MTBE. Both long term and intermediate term analyses were provided and the average cost incurred per gallon of gasoline consumed in California was determined.

3.0 Background

3.1 Goals of the Study

The fundamental goal of the study is determining how much more costly it would be to manufacture gasoline without using MTBE. Refining economics are the key to determining these costs.

There are many different ways of banning MTBE. Since legislators have many alternative ways of accomplishing an MTBE ban, the consultant studies were devised so that different possibilities could be explored. That led to all the different cases that were run by Mathpro.

If MTBE is banned, then it may be replaced by some other oxygenate compound. In this work, tertiary butyl alcohol (TBA), ethyl tertiary butyl ether (ETBE), tertiary amyl methyl ether (TAME) and ethanol were considered as oxygenate alternatives to MTBE. These four materials were chosen because all are approved by EPA and all are produced in commercial quantities already. Other oxygenates might have been considered but all the other oxygenates suffer from one flaw or another. Some are not approved by EPA so it is unclear that they would have appropriate air quality attributes. Others are not produced in commercial quantities so accessing adequate supplies would be risky. It was determined early in the process of designing this study that resources would be most wisely spent looking more intensively at prospects with few risks rather than by trying to evaluate every possible oxygenate.

Changes in the law or regulations might affect how an MTBE ban would be implemented. If federal law is changed to eliminate the oxygenate requirement, then it may be possible to produce CARB gasoline without any oxygenate. Some proposals would grant certain ethanol blends a limited vapor pressure waiver. While other regulatory changes might be envisioned, others were not evaluated in this study.

3.2 Results Sought

The results sought from the study are the increases in gasoline supply costs that would come from a ban on MTBE in each case studied. Price increases, as opposed to supply cost increases, are not directly determined by any part of the study. Some information that might be reasonably expected to lead to price impacts was identified in the study results and will be discussed below.

3.3 Components of the Solution

The three consulting firms, Purvin & Gertz, ESAI and Mathpro, each worked on separate parts of the MTBE ban problem to determine the solution. The work of the three consultants is interdependent and works together to form the whole.

ESAI determined the costs at which other the other oxygenates could be made available. Those costs, for ethanol for example, are not a single number but rather a range of numbers. There is some minimum price that must be paid to get any ethanol for the California market. At that minimum some ethanol would be available but not all ethanol supply would be provided at that price. To attract supplies from other, more costly sources, higher prices would have to be paid. ESAI worked out this relationship between the price California pays and how much oxygenate is supplied not only for ethanol but also for TBA, ETBE and TAME. ESAI's results are referred to as "supply functions", one for each oxygenate. That information is very important to Mathpro's

work as will be discussed more below. One item Mathpro needed to figure out how much CARB gasoline would cost using ethanol instead of MTBE is the price of ethanol.

Purvin & Gertz determined the cost at which CARB-quality gasoline without the oxygenate blended in, known as “CARBOB”, could be made available. Similar to the work that ESAI performed, Purvin & Gertz considered all the locations from which California might access CARBOB, how much CARBOB each location might be able to provide, how much CARBOB ought to cost from each source based on 1997 prices, and how much it would cost to get it delivered to California. The result of this analysis is a supply function for CARBOB. That information also is important to Mathpro’s work.

Mathpro’s goal was to determine the lowest total cost with which the refining system as a whole could comply with any given regulation. Particularly in the intermediate cases in which the refining system could not make substantial investment due to time constraints, Mathpro needed to be able to analyze a “make or buy” decision for the refining industry in California. To do that Mathpro needed to know how much that gasoline could be acquired for from somewhere else.

Mathpro’s work is the center of the analysis. Mathpro developed a sophisticated mathematical representation of how the California refinery system works. This representation is referred to as a linear programming or LP model. LP models take advantage of tremendous computing power to determine the best way for the refining system to operate. Operating in the best way means that fuels are supplied at the lowest possible total cost.

4.0 ESAI/Oxygenate Availability Issues

ESAI has studied the availability of oxygenates including ethanol, TBA, TAME and ETBE. Their study included a review of sources and the costs of accessing supplies. Mathpro used the ESAI information to estimate the cost of adding these oxygenates to CARB gasoline.

4.1 Ethanol

Ethanol is produced mostly from biomass though other routes exist. In the U.S. corn is the most common feed stock for ethanol production. In Brazil sugarcane is more commonly used. Work is being done to develop economic processes for making ethanol from agricultural wastes like rice straw but these are not commercial. Ethanol can be made from petroleum or coal but those sources aren't significant.

There is enough ethanol produced today such that if California could access all the available supply, the state could use ethanol to provide oxygenate for all the gasoline requirements. Ethanol is produced in the U.S. mostly for consumption in states where there are tax credits or subsidies available.

California might not be able to get access to enough of the ethanol that is produced. Some of the ethanol is sold under long term contracts so getting those supplies diverted to California might not be achievable over the near term. In Brazil, most of the available ethanol is dedicated to their own ethanol fuel programs and only part of Brazil's ethanol is available for export. It isn't clear how long Brazil will have an exportable surplus. If MTBE is banned nationwide, then the rest of the nation would be interested in using ethanol to provide some or all of the required oxygen content for their gasoline.

Over the long term more ethanol could be produced. There is ample ability to grow more grain and ethanol plants could be erected in no more time than it takes to install major refinery expansions.

4.1.1 Terminal Blending

Ethanol has to be blended at the pipeline terminals, not just at the refineries. Ethanol is widely used as a gasoline component, frequently in the Midwest. Experience shows that gasoline containing ethanol cannot be shipped using the pipeline system. Water that enters the pipeline system in small amounts along with other products like diesel fuel would cause the ethanol and gasoline to separate rather than staying mixed. To overcome this problem, ethanol is blended with gasoline only when the truck is loaded to carry the gasoline-ethanol mixture to the service station.

California relies on an extensive pipeline system to distribute gasoline and few or none of the pipeline terminals have the equipment necessary to blend the ethanol with the gasoline. It would take one to two years to equip the terminals with the necessary equipment. The requirement for this equipment and the time to install it is a major factor that must be considered if ethanol is to replace MTBE.

4.2 TBA

TBA usually is manufactured as a by-product of chemical manufacturing aimed toward other goals. That kind of processing wouldn't increase under any reasonable set of price expectations. Most of the by-product TBA is converted to MTBE to maximize its value.

Some MTBE plants could be modified to manufacture TBA. The scale of the required modifications is such that they might be accomplished in the intermediate term.

The combination of diverting by-product TBA directly to California rather than to MTBE manufacturing and modifying existing MTBE plants to make TBA instead should be enough to provide adequate TBA to supply all of California's oxygenate requirements.

4.3 TAME

TAME requires amylene as a feed stock which is available in refinery streams. Amylene is not usually separated from gasoline but it is contained within some gasoline streams. A few refineries have TAME units consuming amylene that otherwise would be sold as part of gasoline but most refineries do not have such units.

Unlike ETBE, TAME cannot be manufactured in MTBE facilities. The products are too different from one another for MTBE production equipment to contribute to producing TAME.

There is only very limited TAME capacity. Over the near or intermediate terms, there is only about half enough TAME in the world to supply the oxygenate requirements for California's gasoline. Over the long term, California refineries could make some of their own TAME but combining that with all the TAME manufactured outside California would not be enough to satisfy California's requirements.

4.4 ETBE

ETBE is chemically quite similar to MTBE. One of the feed stocks for MTBE is methanol, a simple alcohol. To make ETBE, ethanol, also a simple alcohol is substituted for methanol. Getting access to enough ETBE to supply California depends on performing this substitution in MTBE production plants.

ETBE can be manufactured in only some of the facilities used to produce MTBE. There are several competing technologies for manufacturing MTBE. Some of these technologies are readily convertible to making ETBE instead although some amount of time is required. Other MTBE technologies do not lend themselves to conversion to ETBE manufacturing. There is enough MTBE manufacturing that occurs in convertible facilities so that California could be supplied with adequate ETBE by this substitution.

5.0 Purvin & Gertz/External Supply Issues

Gasoline supplied from refineries outside California could be very important if California refiners cannot manufacture adequate CARB gasoline economically without MTBE. A refiner outside the state could find it relatively easy to produce small quantities of CARB gasoline as part of his much larger business of producing whatever specifications are needed in his local marketplace. Such a refiner could "cherry pick" from among his blend stocks to find a few to make little CARB gasoline.

5.1 California's Unique Product

California's gasoline product specifications are unique and provide the state a great advantage in meeting important air quality goals. These unique specifications are a distinct disadvantage, however, when trying to find new sources of gasoline outside the state. Only four of the 725 refineries outside California have ever made CARB gasoline. California's ability to tap into distant suppliers in time of need would be much better if the gasoline they already are manufacturing was found satisfactory for the California market.

5.2 Historical Supply Patterns

California has been a self sufficient market for petroleum products for decades. A large local refining industry developed in California in the early part of the 20th century because crude oil was found in large quantities in California. California's geographical isolation from the major refining centers in the U.S. prevented them from supplying us in a cost effective way and nurtured the development of a refining industry that is sized about right to provide all the products the state needs.

Geographical and market isolation continues. There still is no pipeline to carry petroleum products into California from anywhere. Only marine transportation can be used to deliver products to California from distant suppliers.

5.3 Anticipated Supply Sources

The most important supply sources were determined to be Europe and the U.S. Gulf Coast. Other areas either are too small to be important or lack the level of refinery sophistication needed to be able to make much CARB-quality gasoline. Nevertheless some supply can come from other sources in the Middle East, Caribbean, Far East, Latin America and Pacific North West.

5.4 Potential Problem Areas

5.4 1 Jones Act Tankers

Accessing supplies from the U.S. Gulf Coast requires using Jones Act tankers. Jones Act tankers have the characteristics, among others, that they are built in U.S. shipyards and are registered in the U.S. There are relatively few Jones Act tankers, not enough to transport to California all the gasoline and blend stocks that could be produced on the U.S. Gulf Coast. No one has been identified as building new Jones Act product tankers and only two shipyards have been identified as capable of launching such vessels. The Jones Act fleet diminishes each year

because of retirements, many required by federal legislation. Having enough tankers to access supplies from the U.S. Gulf Coast could be a problem.

5.4 2 Advancements in External Quality Requirements

Over time Europe and other areas around the world are advancing their own environmental product specifications. As that happens, the ability of refiners in those areas to supply California with suitable quality gasoline may be impacted. If the stringency of such specifications advances faster than refiners' ability to respond to the requirements, then their surpluses of appropriate quality for shipment here may deteriorate.

6.0 Mathpro/California Supply Issues

Mathpro incorporated supply cost information from ESAI and Purvin & Gertz into a mathematical model that Mathpro developed to determine costs of alternative cases. The ESAI information provided for Mathpro the costs of the alternative oxygenates that might be used in lieu of MTBE. The cost of imported CARBOB or alkylate provided by Purvin & Gertz allowed Mathpro to consider "make or buy" alternatives for the refining industry. Mathpro provided a great deal of information about how refineries could operate, how they might be modified to respond to various alternatives, the quality of the fuels produced and what their yield patterns would be.

Mathpro's economics results are limited to costs of supply. The total costs incurred by the petroleum industry were calculated and the result was divided by the total volume of gasoline produced. Total costs include both capital cost and operating cost. This calculation does not purport to be a price forecast but it does determine the total cost of regulatory alternatives.

The prices of petroleum products determine by whom the costs of any new regulation would be borne. If the price increase is smaller than the cost increase, then the petroleum industry would bear some of the costs while only part would be passed on to consumers. If the price increase is equal to the cost increase, then the consumer bears all the costs. If the price increase is greater than the cost increase, then the consumer would bear more than the total cost and profitability in the petroleum industry would increase. All these possibilities exist but projecting which is most likely to occur is beyond the scope of work undertaken by Mathpro.

6.1 Uses and Limitations of LP Modeling

Linear programming (LP) models are powerful mathematical tools used to analyze complex systems like oil refineries. No other mathematical tool has the potential to find reliably the best way to operate such a system. Consequently, LP models are the standard way to solve problems such as the cost of a new regulation.

LP models have certain inevitable shortcomings. The mathematics of LP models requires that relationships be represented as mathematically linear. There are many important relationships in the real world that are not linear, however. Though users of LP models like Mathpro are able through application of sophisticated techniques to portray such relationships in linear fashion, these are approximations.

LP models rely on voluminous input data to be used to "calibrate" the model. Calibration means organizing the model properly so that the model accurately portrays the behavior of the world in an actual historical period. The data needed to calibrate the model includes details of all the refinery's crude oils and other feed stocks, how each part of the refinery operated, what the capabilities are of each part of the refinery, extensive operating cost information, all the products manufactured, their exact qualities and so forth. If an LP model accurately represents what actually happened before, then it gains credibility that it will accurately portray what will happen in different circumstances in the future. Calibrations are never perfect, however, and imperfections occur because of imperfect or incomplete data describing what actually happened or because of approximations that must be made.

LP models are complicated and it is impractical due to the size of the problem to model every refinery in California separately. Furthermore, there are trade secrecy concerns that would arise if access to calibration data were to be made on a refinery by refinery basis. Instead, all the refineries are modeled together, like one big refinery. This approach allowed for access to good calibration data provided by the refiners under PIIRA and aggregated by CEC staff. A problem

with this approach is that refineries can be “over-optimized” meaning that a shortcoming or constraint in one refinery can be offset by available capacity in another refinery without the modeler’s knowledge. There are ways to minimize such over-optimization which Mathpro used but it cannot be completely eliminated.

6.2 Procedure to Calibrate the Model

A data sheet was sent to each refiner in California to get calibration data for summer 1997 and on-site visits were held with every refining company for them to explain their operations. The data sheets were returned to CEC and the data was aggregated together to preserve trade secrecy and comply with the requirements of PIIRA. The aggregated data was provided to Mathpro for use in the calibration.

Mathpro prepared a model of summertime 1997 conditions. Summertime was chosen because that is when demand for gasoline is greatest and when the load on the refining industry is highest. Summer of 1997 was chosen because summer 1998 was still in the future when this process occurred. Summer 1996 was not chosen because refiners learned a lot about how to make CARB gasoline between spring of 1996 when the program first was introduced and summer of 1997. In the summer of 1996 the refiners did as well as they could do at that time but since the CARB program is complicated, it took a while to figure out the best ways to respond to it.

Mathpro prepared their calibration case and sent it back to CEC and the refining industry for comments. Based on comments received back, an improved calibration case was developed that was finally adopted for use in the study.

6.3 Results of the Analysis

Mathpro’s model was used to determine the cost of various regulatory alternatives. The most important cases were those involving ethanol, TBA, ETBE, no oxygenates and mixed oxygenates. There are variants involving treatment of tax credits and other matters which are viewed as interesting but less critical.

Mathpro ran the model to simulate the refining industry continuing to make other products like CARB diesel needed by California and doing its best to manufacture CARB gasoline also. In many cases trade was needed either to supplement CARB gasoline supplies or to dispose of gasoline components that does not meet the CARB specifications. Trade was allowed in jet fuel or EPA diesel but not in CARB diesel, the source of which would be uncertain.

Mathpro’s results include certain key items. These include how much of each product is manufactured by the California industry, the trade in products and intermediates that is needed, how much of various kinds of refinery capacity must be built in the long term cases, and what the average cost increase is that is attributable to the case..

6.4 Intermediate Term Issues

Intermediate term cases as a group show substantial trade both inbound and outbound. The cases with the most trade are the No Oxygenate cases and the Ethanol cases. The presence of large volumes of trade in these cases should be interpreted as meaning the challenges posed by meeting the predictive model without using oxygenates or with using ethanol in lieu of MTBE are large. Conversely, the absence of substantial trade increases in other cases is indicative that the California refining industry would have less difficulty complying with those cases.

In the No Oxygenate cases 300-400 thousand barrels per day of finished product or blend stock imports are required. In the Ethanol cases about 200-300 thousand barrels of imports are more typical. TBA and ETBE as well as the mixed oxygenate cases showed only limited import volume, 50 thousand barrels per day or less.

Similarly, the No Oxygenate and Ethanol cases generally required the refining industry to dispose of substantial rejected blend stocks. These are gasoline components whose properties do not fit into CARB gasoline very well. Currently such materials are incorporated into gasoline because some other materials offset their negative qualities. The No Oxygenate case had particularly high rejected blendstocks, about 150-200 thousand barrels per day. The Ethanol cases were better in this respect rejecting generally 50-100 thousand barrels per day. As in the case of imports, TBA, ETBE and mixed oxygenate cases all showed little or no rejected blend stocks.

6.5 Long Term Issues

Long term cases show that the refining industry's appetite for imports will continue and the lowest overall cost of supplying California would be achieved by importing substantial parts of the state's gasoline. Import volumes are substantially lower than the intermediate term cases showing about 150-200 thousand barrels per day for the No Oxygenate cases and 90-130 thousand barrels per day in the Ethanol cases. The TBA cases imported small amounts of alkylate for gasoline blend stock and the ETBE and mixed oxygenates had no increase in imports over the current situation.

The major difference between the intermediate term and long term cases is a substantial reduction in the amount of rejected blend stocks. Through investment available only in the long term, refiners would be able to use most of the blend stocks and reject comparatively little.

Mathpro has not evaluated a set of Ethanol and No Oxygenate long term cases that do not involve import increases. The costs attributable to such cases would have to be higher than the cases Mathpro presented because if they were lower Mathpro would have presented these results instead of the ones shown.

STAFF REPORT

SUPPLY AND COST OF ALTERNATIVES TO MTBE IN GASOLINE

TECHNICAL APPENDICES

Report on the Oxygenate Market:
Current Production Capacity, Future
Supply Prospects and Costs Estimates

OCTOBER 1998

CALIFORNIA
ENERGY
COMMISSION

Pete Wilson, ***Governor***

P300-98-013B

Evaluating the Cost and Supply of Alternatives to MTBE in California's Reformulated Gasoline

Project Report
Oxygenate Subcontractor

Task 2: Report on the Oxygenate Market: Current Production Capacity, Future Supply Prospects, and Cost Estimates

Prepared For the California Energy Commission

Under Subcontract No. CM60065W

October 5, 1998

BY:

Energy Security Analysis, Inc. (ESAI)
301 Edgewater Place, Suite 108
Wakefield, MA 01880

Task 2: Report on the Oxygenate Market: Current Production Capacity, Future Supply Prospects, and Cost Estimates

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Section 1 Introduction

1.1

Scenarios and Assumptions

This report covers Task 2 of the Oxygenate Subcontractor activity, detailing the current production capacity for oxygenates, the ability of the oxygenate industry to increase production capacity, and estimated costs for delivery of alternate oxygenates to California.

Within this report, we will assess the current production capacity of the following oxygenates:

MTBE
Ethanol
ETBE
TBA
TAME

Furthermore, this report will assess the costs of supplying each of the various oxygenates to California through various levels of increased Californian demand. The report will also analyze the effect of the various scenarios and policy assumptions specified by the CEC on the delivered price to California.

The scenarios to be analyzed in this study have been defined by the CEC as the following:

I. A reference scenario, in which MTBE continues to be us ed in the California refining industry. All Federal and state regulations regarding the use of MTBE and other oxygenates are presumed to remain in place. The CEC has also specified a slight variation of this reference scenario, in which MTBE continues to be used, but HR 630 (Bilbray bill) is passed, thereby removing the Federal mandate requiring California refiners to supply gasoline to federal non-attainment regions in California.

II. MTBE ban in California

In this scenario, California bans MTBE use in CARB RFG. Within this scenario, six policy assumptions are to be looked at.

A. Current regulations in place: California and Federal regulations regarding gasoline production remain in place and no new regulations are put on the books.

B. HR 630 passes: The Federal mandate requiring California gasoline manufacturers to use oxygen in gasoline is removed.

C. Ethanol RVP Waiver: Gasoline blended with 10% volume ethanol is given a 1 psi RVP waiver. CARB RFG gasoline containing 10% ethanol is thereby allowed to have up to a 8 psi RVP.

D. Tax Credit Ended for Ethanol/ETBE: Federal tax credits granted to ethanol and ETBE are removed.

E. Tax Credit Ended and HR 630 Passes: Combination of policy assumptions B & C.

F. Tax Credit Ended and Ethanol Receives RVP Waiver: Combination of policy assumptions C & D.

III. MTBE ban throughout United States

The policy assumptions for this scenario are the same as the policy assumptions A - F in scenario II (the MTBE ban in California only).

1.2

Supply curves

For each alternate oxygenate, supply curves are provided showing a price/volume relationship for each oxygenate delivered to California under both an MTBE ban in California and an MTBE ban throughout the United States. In addition, a supply curve for MTBE was built for the reference scenario in which MTBE is not banned. Supply curves are considered both for the intermediate term and the long term. The intermediate term is defined as the time period that is long enough to allow the alternative oxygenate for each scenario category to achieve a new equilibrium level, allowing for additions to existing capacity, as long as it does not include grassroots construction (new oxygenate plants). The long term is defined as the time period that is long enough to allow new oxygenate capacity to be built or converted and is associated with a substantial increase in the capital stock of each alternative oxygenate industry.

The assumptions and approaches behind each supply curve are discussed in Sections 4 and 5, and the price/volume relationships are found in various tables in Appendix M. It should be noted that supply curves have not been constructed for each policy assumption. This is because several policy assumptions are expected to have no effect on the *slope* of the supply curves.

For example, the policy assumption of the passage of HR 630 may result in the refinery model choosing a lower volume of ethanol or other oxygenate on the supply curve, but the supply curve itself would not be affected by such legislation. Another example is the policy assumption that ethanol is granted a 1 psi RVP waiver. This would allow ethanol to be used up to 10% of volume in CARB RFG (or 3.5 wt% oxygen), pending new rules that would be required to override California's 2.0 wt% oxygen limit. This may result in the Refinery

Modeler choosing a higher volume of ethanol to be blended in CARB RFG, but the supply curve itself would be unaltered. The removal of ethanol/ETBE tax credits, however, does alter the slope of the supply curves and thus separate curves have been constructed for these policy assumptions.

The "combination" policy assumptions (E & F), which stipulate the removal of the tax credits and either the passage of HR 630 or an RVP waiver for ethanol, do not have separate supply curves. Instead, it is expected the refinery model will utilize the tax credit scenario supply curves and choose volumes on that curve that are consistent with either the removal of the oxygen mandate or the granting of an RVP waiver to ethanol. For each oxygenate, including MTBE, the various capital costs involved in increasing capacity are discussed.

Section 2.

Global Oxygenate Production Capacity and Demand Assessment

This section outlines the current capacity for oxygenates in the U.S. and around the world. A list of all identified oxygenate plants in the world, by nameplate capacity when possible, can be found in Appendix A. This section also specifies volumes of oxygenate capacity that are scheduled to come online in the future. A list of these projects can be also found in Appendix A.

2.1 MTBE

SUPPLY

Global MTBE production capacity currently totals about 523,000 b/d, with plants located in North America, South America, Europe, Asia/Pacific, Eastern Europe, and the Former Soviet Union (FSU).

MTBE production capacity is dominated by North American producers, whose production capacity is 248,000 b/d or nearly 50% of the world total. Western Europe and the Middle East own the next largest segment of world capacity, with facilities totaling 93,000 b/d and 83,000 b/d respectively.

In addition to present capacity, there is an additional 52,000 b/d of capacity around the world that is either currently under construction or in the engineering stage. Most of this capacity will be coming on-line within the next two years. This includes a 19,000 b/d plant in Canada that will have the dual ability to produce MTBE or ETBE.

Building a new refinery-based MTBE plant using C4s from an fluid cat cracker unit would cost about $6,000-$10,000 per daily barrel, and would take an average of 1.5 years to construct. Existing refinery-based MTBE units are feedstock-limited and it is not possible to expand the present capacity of refinery-based ether units, as the isobutylene feedstock is a byproduct of the refinery process and the source of this by-product cannot generally be expanded. However, there are many refineries without MTBE plants that have large enough FCC units to support commercial volumes of MTBE production. There is approximately 2.2 million b/d of FCC capacity in the U.S. without associated MTBE production. Using the benchmark of 1,000 b/d of MTBE production for every 25,000 b/d of FCC capacity, an estimated 87,000 b/d of additional MTBE production could be built at U.S. refineries.

Building a world scale MTBE plant (mixed butanes/dehydrogenation) would cost on the order of $20,000-28,000 per daily barrel and would take 1.5 years to construct. Unlike FCC-based units, butane plants can be expanded. Industry data suggests that expanding plants costs approximately $10,000 per daily barrel.

In addition to 523,000 b/d of present capacity and the 52,000 b/d of capacity either under construction or in the engineering phase, there are several MTBE projects around the world

that are more tentative in nature. The total amount of this potential capacity is approximately 112,000 b/d. These projects are either only in the planning stages or little information was available.

DEMAND

MTBE consumption is dominated by the U.S., with demand of about 250,000 b/d. Most MTBE is used to comply with mandated oxygen content rules for gasoline supplied to either RFG or wintertime carbon monoxide areas. A small amount may be utilized for octane enhancement.

In Europe, MTBE demand is estimated at about 60,000 b/d. MTBE use in Europe is essentially confined to octane enhancement, and about 6,000 b/d is exported to the United States. Eastern Europe (including the FSU) currently consumes about 10,000 b/d of MTBE.

In Asia, MTBE is used as both an octane enhancer and for environmental reasons. South Korea, for example, has a 1% oxygen content mandate for gasoline. Total Asian consumption is estimated at about 40,000 b/d.

Latin American consumption totals an estimated 17,000 b/d, and the Africa/Middle Eastern region consumes an estimated 10,000 b/d.

2.2 Ethanol

SUPPLY

Ethanol production around the world differs widely both by feedstock type, composition, and use. Ethanol feedstock can be either synthetic (petroleum or coal derived) or agricultural (corn, sugarcane, wine, whey, other biomass). Furthermore, ethanol is used in beverages or sold for use as an industrial solvent and as a building block for industrial organic chemicals. Finally, it is also produced for fuel, either as “hydrous” (containing about 5% water) ethanol or “anhydrous” (water-free) ethanol.

Fuel grade ethanol production is dominated by North America and Brazil. Total capacity in the U.S. is about 107,000 b/d, with another 13,000 b/d of synthetic ethanol production capacity. Canadian output capability is about 2,700 b/d. In addition to the present U.S. capacity, there is an estimated 13,000 b/d of capacity that has shut down over the past few years. Brazilian ethanol capacity is around 260,000 b/d. France is probably the next most advanced country in terms of fuel grade ethanol production, with total capacity estimated at about 8,000 b/d. Currently only a maximum of about 2,000 b/d of ethanol is used, mostly for production of ETBE in France. Other fuel grade ethanol production is limited to small pockets around the world, either for actual blending with gasoline (in New South Wales, Australia, for example about 170 b/d of ethanol is used in a 10% blend with gasoline) or for demonstration purposes.

Scanning the rest of the globe, ethanol production is devoted either to the beverage industry or the petrochemical industry. Most of the ethanol production for beverage and industrial use is located in China, India, Europe and Russia. Synthetic ethanol fills out the world balance,

with about 32,000 b/d of capacity in the U.S., Europe, South Africa and Saudi Arabia.

In terms of bio-ethanol projects coming on-line in the near future, approximately 5,200 b/d of capacity is currently being built or remains in the engineering stage. Most of this future capacity will be located in the U.S. and Canada. In addition to capacity being built or engineered, approximately 17,000 b/d of capacity (again, mostly in the U.S. and Canada) can be identified that is only in the proposal or planning stage (see Appendix M, Table M-2 for a complete listing).

Expansion of ethanol production can be accomplished in several ways. Reconfiguration and debottlenecking of existing plants can increase ethanol output. Redirecting starch from the manufacture of other finished products to ethanol production can also increase ethanol output. For example, more ethanol could be manufactured at the expense of corn sweetener volume. Finally, plants could produce less industrial grade and potable alcohol and more fuel grade ethanol. These conversions could be accomplished relatively quickly, within about 90 days. It is estimated that the wet milling ethanol plants in the U.S. could provide an additional 200 million gallons per year (13,000 b/d) of extra capacity if these conversions were made, at a cost of $.80 per annual gallon. However, there are limits on how much capacity can be converted to fuel ethanol due to existing term contracts for other corn products, which producers must honor.

Dry milling ethanol plants are less flexible in producing extra output. Most run at capacity currently, and could only add new throughput by adding new capital stock, such as a new boiler. This would cost about $2.00 to $2.50 per annual gallon and could be accomplished within a year.

Adding significant quantities of new wet milling capacity would also take close to a year. The cost for building new ethanol capacity is estimated at $2.00 per annual gallon for wet mill plants to $2.50 per annual gallon for dry mill plants (e.g., a 10 million gallon per year greenfield plant would cost $20 million to $25 million dollars in capital.)

DEMAND

Fuel ethanol demand is dominated by the U.S. and Brazil. We estimate that the U.S. consumes on a yearly average about 80,000 b/d of fuel ethanol. Of this, about 40,000 b/d is used to comply with the oxygen requirement for making Federal reformulated gasoline (RFG) and oxygenated gasoline for Federal carbon monoxide wintertime programs. The rest of ethanol supply, about 40,000 b/d, is used voluntarily as a gasoline extender, usually in a 10% mix of ethanol and 90% gasoline, commonly called gasohol.

In Brazil, fuel ethanol demand is about 220,000 b/d. This figure represents two different types of ethanol consumption: that of dedicated ethanol vehicles, and that of vehicles that run on traditional gasoline. Of Brazil's total automobile fleet, approximately 4 million cars are designed to run on 100% hydrous ethanol. Furthermore, Brazil requires that all gasoline supplied in the country contain a mixture of 24% anhydrous ethanol. This means that of Brazil's total ethanol production capacity, about 85% cannot be exported outside of the country, either because of law (the 24% mandate) or because of dedicated use (vehicles that run on hydrous ethanol).

Fuel ethanol use elsewhere around the world is extremely limited. Ethanol production around the world is devoted to industrial uses, such as solvents, and for the beverage industry. An estimated 113,000 b/d is used for industrial uses, and an estimated 73,000 b/d is used for making alcoholic beverages.

2.3 ETBE

SUPPLY

ETBE production around the world stands at about 91,000 b/d, and this includes MTBE plants with dual capacity to produce ETBE. Most of the capacity is located in the U.S. (53,000 b/d). About 21,000 b/d of new capacity is currently being built, but the majority of this a result of a 19,000 b/d combined ETBE/MTBE plant being constructed in Canada.

ETBE capacity could be increased significantly by switching MTBE production to ETBE production. The costs and time periods needed to convert from MTBE production to ETBE production depend on the configuration of the existing ether plant; specifically, whether it uses fixed-bed or catalytic distillation process technology. With catalytic distillation process technology, the capital cost to convert from MTBE production to ETBE production would be on the order of $1 to $2 million, and about one year would be required for the alterations to be made. Fixed-bed ether units, on the other hand, would only need new instrumentation, and this would cost significantly less, probably about $200,000 per plant. This switchover could be accomplished within 6 months. It is unlikely that MTBE units outside the U.S. would make a similar conversion to ETBE production, either because they would have little access to ethanol feedstocks or would be unable to capture the subsidy that makes ethanol an affordable feedstock, or both.

As with the case of MTBE plants, existing refinery-based (FCC) ETBE units cannot be expanded, as isobutylene is a byproduct of the refinery process and the source of this byproduct cannot be expanded. As mentioned previously, there are many refineries without MTBE or ETBE units that have FCC units large enough to support commercial volumes of ether production. These ETBE units could be built at a cost of $6,000 to $10,000 per daily barrel. Moreover, butane-based world scale ether plants can be expanded, at a cost of $10,000 per daily barrel.

DEMAND

ETBE is used in limited quantities both in the U.S. and in France.

2.4 TAME

SUPPLY

TAME production is fairly limited around the world, with total capacity of only about 46,000 b/d. North America leads production, with capacity of about 22,000 b/d. Latin America has capacity for about 9,400 b/d while Europe has capacity of about 7,100 b/d. In addition, there

is 16,000 b/d of TAME capacity either being planned or constructed, and there may be several others which could bring global capacity as high as 90,000 b/d.

TAME capacity can only be built economically within the refinery gate, due to the limited nature of isoamylene feedstock supply outside of the refinery process. Building TAME capacity at a refinery (Fluid Cat Cracker-based) costs in the range of $6,000-$12,000 per daily barrel (a somewhat higher range than building FCC-based MTBE units), and would take 1.5 years to construct. Expansion of existing TAME units is not possible because isoamylene is a byproduct of the refining process and the byproduct source cannot be expanded. However, additional TAME production could be built at refineries with large FCC units, but that do not now have TAME plants. However, there are many refineries without MTBE plants that have large enough FCC units to support commercial volumes of MTBE production. There is approximately 2.2 million b/d of FCC capacity in the U.S. without associated MTBE production. Using the benchmark of 1000 b/d of MTBE production for every 25,000 b/d of FCC capacity, an estimated 87,000 b/d of additional MTBE production could be built at U.S. refineries.

TAME plants cannot be economically converted from MTBE plants. The dynamics of the reaction are very different, and the process configuration would need to be changed. It would be more economic to build new TAME units in refineries without any ether units.

DEMAND

U.S.-based TAME units have generally run at low utilization rates (less than 50%). TAME is generally used for complying oxygen requirements in RFG areas.

2.5 TBA

SUPPLY

TBA production capacity is limited to about 60,000 b/d worldwide. 35,000 b/d of this is located in the Gulf Coast, 26,000 b/d is located in Europe, and 3,500 b/d is located in Russia. No new TBA projects are planned in the U.S. or around the world.

TBA capacity would be increased by switching MTBE production to TBA production. The capital expenditures required would be adding an extra tower at the ether unit and tankage for co-solvent. Total additional capital required for the conversion would be on the order of $4-5 million, and the process would take about 1.5 years.

TBA is a by-product of propylene oxide manufacturing. Existing TBA units cannot be expanded due to the limited volumes of propylene oxide that are produced. Building a new refinery-based TBA unit would cost in the range of $9,000 to $12,000 per daily barrel.

DEMAND

TBA demand is currently limited to MTBE production, or other higher value chemical end uses.

Section 3.

SUPPLY COST ESTIMATES FOR REFERENCE CASE SCENARIOS

The Reference Case for this report is defined as "business as usual" in the California refining sector; that is, MTBE continues to be used in California under current regulations. There is also a second Reference Case, which is "business as usual" with the stipulation that HR630 is passed, ending the federal mandate for oxygenate use in gasoline supplied to the federal non-attainment regions in California. California refiners will therefore have the flexibility of using zero oxygenate to produce CARB RFG during the summer gasoline season. For the purposes of this report, however, the existence of this second reference case will not affect the slope of the MTBE supply curve. There is only one reference curve; under the HR630 reference case, the refinery model, which uses the supply curves presented in this report as an input, will simply read a lower demand volume with its subsequent price level.

The price/volume relationships analyzed below are found in various tables in Appendix M.

3.1

Intermediate Term MTBE Cost Estimates

California's supply of MTBE comes from several sources. Of the roughly 100,000 b/d of MTBE consumed in California, only a maximum of 13,000 b/d is produced in-state by California refiners with MTBE production capacity. The rest is imported: roughly 47,000 b/d from producers in Canada, the Middle East, Venezuela, and Asia, and 40,000 b/d from U.S. Gulf Coast suppliers.

California MTBE capacity
12,700 b/d

Foreign imports

Canada	15,600
Saudi Arabia	23,700
Venezuela	4,600
South Korea	1,500
Singapore	1,100
Netherlands	700
Total:	47,100

(Source: Dept. of Energy, 1998 year-to-date data)

Gulf Coast imports
40,200 (ESAI estimate)

MTBE is produced much more cheaply by Canadian and Saudi producers because of the surplus of LPGs in those regions. Butane prices in Canada, for example, have generally been roughly half that of U.S. spot prices. Middle East prices are similarly inexpensive relative to other regions.

Therefore, in determining the relationship between cost and volume for MTBE delivery to California, Canadian and Middle East MTBE volumes are the first and least expensive incremental deliveries.

The butane dehydro process starts with 1.0 gallon of normal butane, which is isomerized to isobutane and then dehydrogenated into isobutylene. This is then reacted with 0.344 gallons of methanol at a total variable operating cost of about 7 cents/gallon. Assuming a methanol price of 61.2 cents/gallon, a butane cost of 14.3 cents/gallon [1], and a 10 year capital life using a 15 percent discount factor for a 15,000 b/d plant, the selling price of Canadian/Middle East MTBE is calculated at 73.3 cents/gallon. Canadian MTBE (15,600 b/d) is delivered to California the cheapest, at 76 cents/gallon, due to low transportation costs, and Saudi MTBE (23,700 b/d) is delivered to California at 83 cents/gallon, due to incrementally more expensive transportation costs. The selling price of MTBE derived from U.S. Gulf Coast dehydro merchant plants (40,200 b/d) is higher, at 88 cents/gallon, due to more expensive butane costs (assumed to be 28.6 cents/gallon for this study).

A gallon of MTBE made from FCC-derived isobutylene is manufactured by reacting 0.8 gallons of isobutylene with 0.344 gallons of methanol at a varable operating cost of 3.4 cents/gallon. Using the methanol price of 61.2 cents/gallon, a butane cost of 28.6 cents/gallon, and a 10 year capital life using a 15 percent discount factor for a 3,000 b/d plant, the selling price of FCC-derived MTBE is 86.5 cents/gallon. The cost of butylene as alkylation feedstock was calculated as 70 cents/gallon, based on alkylate value and butane prices located in Appendix K.

In summary, the intermediate term supply curve for MTBE is built by determining the origin of California's supply and calculating the differential production costs for those volumes.

There is enough *global* capacity to meet any new sudden MTBE demand surge with imports. In other words, MTBE could be supplied by offshore producers before any new large scale plants would need to be built in the U.S. Out of a global capacity of about 520,000 b/d, about 390,000 b/d is currently produced (a utilization rate of 75%). With 130,000 b/d of spare capacity, the world market could absorb an increase in U.S. demand above its current 250,000 b/d consumption rate. Most of this would be supplied by Europe and the Middle East, regions of the world where most excess capacity exists.

3.2

Long Term MTBE Cost Estimates

[1] The Canadian/Middle East price is estimated to be half of the 28.6 cents/gallon benchmark price for US butane used in this study

In the long term, the supply curve will be flatter, as more low-cost MTBE production capacity comes on line. In Appendix A, Table A-1, several new MTBE plants are identified which are either being constructed or are in the planning stages. This includes 19,000 b/d of Canadian capacity, as well as close to 50,000 b/d of Middle Eastern capacity. All of this capacity is low-cost, as it will be located in LPG-surplus regions.

To build the long term supply curve for MTBE delivery to California, the same cost formulas from Section 3.1 are used. However, using projected future MTBE capacity from Table A-2, more low-cost MTBE is available in the long term. For example, roughly 31,000 b/d of Canadian MTBE is delivered to California at 76 cents/gallon, while 60,000 b/d of Middle Eastern MTBE (Saudi Arabia, Iran, Qatar) is delivered to California at 83 cents/gallon. It is assumed that 75 percent of the new capacity in the Middle East and Canada is available for delivery to North America.

The rest of the supply curve is filled out with production from California (allowing for an additional 2,000 b/d of new capacity to come online) as well as Latin American production. U.S. Gulf Coast production is not included as it is higher-cost than California's alternatives. In the long run, US Gulf Coast MTBE is likely to continue to be imported to California; however, the quantity of low-cost MTBE coming on-line from LPG-surplus areas suggests that Gulf Coast producers will have to accept a lower price due to the cost pressure from producers in Canada and the Middle East.

Section 4.

SCENARIO: *MTBE BANNED IN CALIFORNIA ONLY*

SUPPLY COST ESTIMATES FOR ALTERNATIVE OXYGENATES

The first scenario in this study assumes that MTBE is banned in the state of California. Different policy assumptions are examined with respect to their effect on the cost of alternative oxygenates within the marketplace. With the exception of the policy assumption of HR 630 passing (which would end the federal oxygen mandate in CARB RFG and thereby allow California refiners the option of using no oxygenate at all during the summer season), other oxygenates are needed by California refiners to comply with federally and state mandated minimum oxygen levels in CARB RFG.

The effect of a California ban on MTBE on the cost of ethanol, ETBE, TAME, and TBA is analyzed in Sections 4.1 through 4.4. While this study examines six different policy assumptions (or combination of policy assumptions), the only policy assumption that will have an impact on any of the supply curves will be those involving removal of tax credits for ethanol and ETBE. This is because while HR 630 may reduce the ultimate volume of oxygenate (whether MTBE, ethanol, ETBE, etc), it will not change the slope of the supply curve. Likewise, granting ethanol a 1 psi RVP waiver may result in a higher amount of ethanol consumed in California, but it will not change the slope of the supply curve. Since tax credit issues change the ultimate price of ethanol and ETBE, this is the only policy assumption that will result in a different supply curve for these oxygenates.

4.1

Ethanol Use in California (MTBE Ban in California Only)

Four supply curves need to be considered for the alternative oxygenate ethanol. The first set of supply curves considered will represent the price of ethanol with current tax regulations in place (i.e., gasoline blenders are eligible for up to a $.54/gallon tax credit for ethanol in blends of up to 10%, and a pro-rated tax credit for blends of less than 10%, such as 7.7% and 5.7%), both for the intermediate term and the long term. The second set of supply curves will represent the price of ethanol without the tax credit, both for the intermediate term and the long term.

4.1.1

California' ethanol requirements

If MTBE were banned in California, and ethanol was chosen to replace it as the oxygenate used for blending with CARB RFG, less ethanol than MTBE would be needed under current regulations *for oxygen purposes only (not volume)* in CARB RFG because ethanol contains almost twice the amount of oxygen by weight than does MTBE.

Ethanol contains almost 35% oxygen, and therefore only about 5.7% ethanol is needed in a gallon of gasoline to achieve the 2% oxygen target. This study assumes that California consumes on average about 965,000 b/d of gasoline in the intermediate term. The amount of ethanol needed under the current regulations *for oxygen purposes only (not volume)* is therefore about 55,000 b/d to achieve a 2.0 wt. % oxygen level, and 97,000 b/d to achieve a 3.5 wt. % oxygen level. In the long term, California is assumed to demand 1.022 million b/d of gasoline. The amount of ethanol needed at this demand level is about 58,000 b/d to achieve a 2.0 wt. % oxygen level, and 102,000 b/d to achieve a 3.5 wt. % oxygen level.

4.1.2

Ethanol availability in the U.S.

Currently, the U.S. produces about 80,000 b/d of fuel ethanol on an average annual basis, and imports relatively small volumes occasionally from Central America. On-line capacity in the U.S. and Canada equals 110,000 b/d. Therefore, the U.S. fuel ethanol industry produces at roughly 70% of capacity on an annual basis, and there is about 30,000 b/d of spare capacity that could be used to supply California. This spare capacity is generally concentrated among the major producers of ethanol. While there are several ethanol plants that have shut down over the years, and might be counted as capacity that could come online to meet Californian demand, we can assume that these plants are not *currently* operating because they are not competitive. If they were competitive they would be producing at the current price for ethanol ($1.20/gallon). Also, these small producers do not have the economies of scale that larger producers like ADM currently enjoy. ADM and the larger producers would therefore increase production or increase capacity before some of the smaller producers came back to

production.

4.1.3

Ethanol Supply curve Estimates (Tax Credits Available)

The price/volume relationships analyzed below are found in various tables in Appendix M, Table M-3 and M-4. It is assumed that all subsidies including tax credits for blenders are in place throughout the country.

4.1.3.1

Intermediate Term Cost Estimates

Ethanol is blended in gasoline (primarily in the Midwest or Padd II region) where it is more economical to use than MTBE or can be blended with regular or subgrade unleaded gasoline to make a midgrade or premium gasoline.

In the intermediate term (i.e., before substantial new ethanol capacity could be built and substantial quantities of ethanol supplied to the market), California CARB RFG blenders would have to outbid these other users of ethanol in order to secure ethanol supply and comply with California and Federal oxygen regulations. In other words, the price of ethanol will have to increase to the point where it is cheaper for ethanol blenders outside of California to switch to MTBE for their oxygenate use, or cheaper to buy 100 percent petroleum-based gasoline instead of using ethanol in a mix with regular unleaded gasoline (gasohol).

In order to make these comparisons, ethanol needs to be valued correctly. Ethanol's value to gasoline blenders will first depend on whether it is being used as an oxygenate in oxygenated gasoline, or whether it is being used in gasohol as a gasoline extender.

If used as an oxygenate, ethanol's value will depend on the cost of MTBE, the cost of octane and Reid Vapor Pressure (RVP). Using a 2.7 wt. % oxygen level in oxygenated gasoline, ethanol's value can be expressed using the following equation [2]:

$$P_{EOH} = (0.852\ P_{B\text{-}MTBE} - 0.923\ P_{B\text{-}EOH} + 0.148\ P_{MTBE} - C_{EOH})/0.077$$

Where

P_{EOH} = Price of ethanol
$P_{B\text{-}MTBE}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with MTBE.
$P_{B\text{-}EOH}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with ethanol
P_{MTBE} = Price of MTBE
C_{EOH} = Any costs associated with blending ethanol

If used as a gasoline extender, ethanol's value will depend on the retail price of gasoline, the rack price of gasoline, and the cost of octane. Using the typical 10 percent blend of ethanol

[2] The derivations of this formula (EOH valued as an oxygenate) and the following formula (EOH valued as gasohol), provided by MathPro, Inc., can be found in Appendix B.

found in most gasohol, ethanol's value can be expressed using the following equation:

$$P_{EOH} = -\left(P_{R\text{-}MOGAS} - P_{MOGAS} - P_{R\text{-}GASOHOL} + 0.9\, P_{B\text{-}EOH} + C_{EOH} \right) / 0.1$$

Where

P_{EOH} = Price of ethanol
$P_{R\text{-}MOGAS}$ = Retail (pump) price of pool gasoline
P_{MOGAS} = Rack price of pool gasoline
$P_{R\text{-}GASOHOL}$ = Retail (pump) price of gasohol
$P_{B\text{-}EOH}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with ethanol
C_{EOH} = Cost associated with blending ethanol

In order to determine the price/volume relationships, blocks of outside supply are identified, and breakeven ethanol values are determined to attract these volumes away from their markets.

The blocks of ethanol used for this study are on a state-by-state basis. Ethanol volumes consumed in each state were estimated using 1996 ethanol usage data from the Federal Highway Administration (percentages of 10% and less than 10% blends of ethanol used in total state gasoline usage) and applying it to 1997 gasoline sales data supplied by the Energy Information Agency *Petroleum Marketing Annual.*

Since gasoline prices (and to a certain extent, MTBE prices) differ in each state, ethanol will be valued differently according to its market. Retail and rack gasoline price data from the U.S. Energy Information Agency's *Petroleum Marketing Annual* publication were used to determine gasoline prices for all states that consume ethanol. Prices were adjusted for use in this study by basing them on a base of 62 cents/gallon pool gasoline rack price and a $1.00/gallon retail price and then adding a differential based on the relative prices found in each state. For example, Indiana's rack price for gasoline was 1.5 cents/gallon higher than that of Mississippi, which had the lowest U.S. rack price; therefore, for the purposes of this study, the rack price for Indiana is 63.5 (62 plus 1.5). See Appendix C for a ranking of state-by-state rack and retail gasoline prices.

Using the formulas expressed above, ethanol values were determined for each state. Arizona, Nevada, Washington, California, New Mexico and Colorado were assumed to use ethanol for oxygenate blending instead of as a gasohol (thus the higher value for ethanol). Several states, notably Ohio, South Dakota, Illinois and Missouri, have state incentives for ethanol use, in the form of an income tax exemption. The presence of such state subsidies increases the price at which ethanol will be bid away from these states, by 10 cents per gallon of ethanol for Ohio, 13 cents for Illinois (estimated using the 2% sales exemption on a 6.25% sales tax), and 20 cents for Missouri and South Dakota. The estimated volume of ethanol sales (b/d) and calculated ethanol values (cents/gallon) for each state are listed below:

Mississippi	126	63.1	Maryland	173	63.7
Louisiana	474	63.3	Alabama	1,302	64.0
North Carolina	72	63.6	Tennessee	1,021	64.4
Wisconsin	2,105	63.6	Texas	3,410	65.1
Pennsylvania	4,419	63.6	New York	1,492	65.2

N. Dakota	385	65.2
Nebraska	1,546	65.2
Kentucky	304	66.1
Florida	144	66.2
Indiana	5,391	66.2
Kansas	312	66.7
Iowa	4,277	67.2
Michigan	2,925	67.6
New Jersey	821	69.9
Ohio	12,883	74.1
Illinois	10,392	78.3
S. Dakota	1,175	85.9
Missouri	1,243	87.1
Arizona	1,453	90.7
Nevada	827	91.0
Montana	42	91.7
Washington	1,939	91.8
California	2,000	94.7
New Mexico	1,156	95.4
Colorado	2,248	96.1
TOTAL:	66,119	

In the supply curve constructed from the above data, the block representing ethanol consumed in Minnesota is excluded from the volume that can be bid away to California blenders. Minnesota has a year-round oxygenate mandate stipulating a 2.7% minimum oxygen content in all gasoline sold in the state. According to industry sources, the language in this regulation precludes the use of MTBE, and as such, the mandate amounts to an ethanol mandate. Thus, there is approximately 13,500 b/d of ethanol consumed in Minnesota that cannot be bid away.

There are two other blocks of supply that need to be considered. These are volumes of ethanol imported from the Caribbean and ethanol that could be supplied by increasing U.S. utilization capacity to 100 percent.

U.S. law (the Caribbean Basin Initiative) states that the equivalent volume of up to seven percent of U.S. ethanol production can be imported duty-free into the United States. Historically, this has been essentially unfinished ethanol from beer still/wine alcohol that is exported from the European Union, and sent to countries like Jamaica and El Salvador, where it is upgraded and sent to the U.S. Industry sources report that the ethanol is priced at approximately 60 cents/gallon, and that freight and insurance would bring the delivered price to California to almost 83 cents/gallon. With an assumed production of 110,000 b/d in the U.S., the Caribbean ethanol volume available is estimated at 7,700 b/d.

Since U.S. ethanol capacity is 110,000 b/d and the average annual production is 80,000 b/d, there is approximately 30,000 b/d of ethanol that can be supplied to California. Because individual ethanol plant data is not available, and each plant runs on different economics, it is not possible to determine what price for ethanol would cause each plant in the U.S. to reach 100 percent of capacity.

However, it is possible to create a notional ethanol producer's margin, and compare this to historical utilization capacity. The margin for an ethanol producer is equal to the price received for ethanol and other corn by-products (such as distiller's grains and starches) minus the cost of producing ethanol (composed mostly of corn feedstock costs). Historical price data for corn, dried distiller grains, gluten meal and gluten feed were obtained, as well as other typical variable and fixed cost information for both wet and dry milling ethanol producers (See Appendix E & F). A notional margin for both wet and dry milling producers was calculated on a monthly basis for the last six years, and compared to production data from the Energy Information Agency (see Appendix G). According to this data, it appears that the only time that utilization rates in the U.S. reached near 100% (winter 94-95), the

notional margin (averaged for both wet and dry milling producers) was approximately 40 cents/gallon.

The historical average net production cost (a weighted average for both wet and dry milling producers), according to the data used in this report, has been approximately $1.03/gallon over the past six years. Therefore, the price required to bring U.S. production to full capacity is equal to the $1.03/gallon net production cost plus 40 cents/gallon margin, or $1.43/gallon. Net of the 54 cent/gallon subsidy, this equals 89 cents/gallon.

With approximately 58,000 b/d of ethanol bid away from other states, 7,700 b/d available through the Caribbean, as well as 30,000 b/d available by boosting production, a supply curve can be constructed up to demand levels of 98,000 b/d. This is the approximate demand level that would be necessary for California if ethanol were granted a 1 psi RVP waiver, effectively allowing blenders to use up to 3.5 wt. % oxygen level in CARB gasoline.

MTBE demand will fall to zero in California as a result of a ban on its use. Ordinarily this would result in a severe drop in MTBE's price, and perhaps a knock-on effect in the price of other oxygenates. However, blenders outside of California that use ethanol will need to replace oxygen or octane if ethanol is bid away; and they will most likely use MTBE. Since end-users of ethanol and MTBE will in essence be swapping demand for oxygenates, there should not be any net change in price for MTBE.

In summary, the intermediate term supply curve for ethanol delivered to California is constructed by determining the correct ethanol value in each state that consumes the fuel, and assuming that the amount consumed by each state will be bid away by Californian end-users once the price has risen to breakeven levels above which the original consumers would find it too expensive. Minnesota ethanol is not considered, and in addition there is 7,700 b/d of ethanol that is available through the Caribbean, as well as 30,000 b/d of ethanol that is available by increasing producers' utilization rates to 100%.

4.1.4.2

Long Term Ethanol Cost Estimates

Within 2-3 years, another 5,300 b/d of ethanol capacity in the U.S. and Canada that is either under construction or in planning/engineering stages would come on line and add to supply. Furthermore, the increased demand for ethanol would justify the construction of nearly 17,000 b/d of capacity in the U.S. that has already been planned or proposed (see Appendix A, Table A-2, for a listing of plants expected to come on-line). In addition to the projects already planned, new producers will enter the market, attracted by higher intermediate term prices and increased demand caused by a switch to ethanol consumption in California.

The long term scenario assumes that in addition to the approximately 80,000 b/d of ethanol already consumed in the U.S. (excluding California) another 58,000 b/d to 102,000 b/d would be produced to supply California's needs. Assuming that approximately 91% of ethanol will continue to be processed with corn feedstock, and that approximately 2.6 gallons of ethanol are produced from a bushel of corn, this increased demand will require additional feedstocks

of 310 to 550 million bushels of corn.

In a long term time period, the additional required volumes of corn feedstock will be supplied in response to higher demand and higher corn prices in the intermediate term. Additional corn production is expected to respond to the long term supply elasticity of price for corn (the percentage change in corn price divided by the percentage change in supply of corn). The U.S. Department of Agriculture (USDA) has generally used the value of 0.3 as an estimate for this value. Using this elasticity value, it was possible to calculate the increasing price for corn at various volumes additional ethanol supplied to the market. For the purposes of this study, a baseline of $2.60/bushel was used. See Appendix J for calculations.

It is also expected that as a result of the additional processing of corn for ethanol production, there will be a large increase in the supply of by-products, such as distillers' dried grains (DDG), corn gluten feed, corn gluten meal and corn germ. It expected that the price of these by-products will decline in response to the long term supply elasticities for these products. Previous USDA studies have reported that an increase in ethanol production of 4.8 billion gallons would decrease corn gluten meal prices by 7 percent, corn gluten feed prices by 12.3 percent, and distillers' dried grains by 4 percent. [3]

Using this data, long term supply elasticities were calculated for each by-product of ethanol production. These elasticities were then used to determine the price of DDG, corn gluten feed, corn gluten meal, and corn germ at various volumes of ethanol supplied to the market in the long term. See Appendix J for calculations.

By determining the long term price of corn and the long term price of ethanol by-products, it was possible to calculate long term net production costs at various volumes of ethanol. All other fixed and variable costs besides corn cost and by-product prices were held constant.

In the long term scenario, ethanol prices are expected to decline to their marginal cost of production as calculated above. Since most production will still be located in the large corn-producing states, the transportation cost of 15 cents/gallon remains.

4.1.4

Loss of Ethanol Tax Credit

The following section estimates intermediate and long term cost of ethanol delivered to California in the absence of the 54 cent/gallon Federal subsidy for ethanol.

The approach used for determining the supply curve for ethanol delivered to California in the absence of a Federal subsidy is to estimate the pattern of supply and use of ethanol, given the loss of the ethanol tax and with no California ban of MTBE, i.e., the current regulatory situation, but with no ethanol tax break. As is explained below, this study assumes that little or no ethanol use will continue. The supply curve for delivery of ethanol to California is then

[3] House, R., M. Peters, H. Baumes, and W.T. Disney "Ethanol and Agriculture: Effect of Increased Production on Crop and Livestock Sectors," USDA, Economic Research Service. Agricultural Economic Report Number 667. May, 1993.

constructed by estimating the price necessary to induce ethanol plants to resume operation.

4.1.4.1

Intermediate Term Cost Estimates
Ethanol Without Tax Credits

The General Accounting Office has reported that if the tax credit for ETBE and ethanol was revoked, then production in the U.S. of these fuels would decline by at least 50% and perhaps to zero. As the tax credit is eliminated, the effective price of ethanol rises for end-users, discouraging demand, encouraging gasoline blenders to use cheaper substitutes like MTBE for oxygenate needs and use of 100% gasoline instead of a 10% ethanol blend. As demand drops off, the price of ethanol will decline, causing ethanol producers to make less ethanol. As the cost of producing ethanol is high relative to gasoline and MTBE, if the ethanol selling price falls too far, many producers will go out of business. In other words, the tax credit available for ethanol keeps the price of ethanol artificially high. Without the subsidy, ethanol prices would have to decline substantially to be either competitive with MTBE or gasoline.

Since the prices used in this report for gasoline and MTBE are lower than the calculated production cost for ethanol, it is assumed in this study that ethanol production would fall to zero in the U.S. In order for producers to supply ethanol, the price will have to rise to at least the cost of production.

Data on production costs are not available for individual ethanol producers in the U.S. Instead, a notional net production cost formula can be used, based on the cost of corn and the credits received for ethanol by-products such as DDGs, corn germ, corn gluten meal and corn gluten feed as in Section 4.1.4.2. According to interviews with industry members familiar with the ethanol industry, the most important cost segment for the typical ethanol producer is the cost of corn. Corn prices can vary substantially from state to state. In Appendix H, historical corn prices for the last 6 years are listed for each state. Not surprisingly, the lowest corn prices in the country are found in those states with the largest amount of corn output.

To determine the price of ethanol needed to induce production in the absence of the subsidy, the net cost of ethanol production was calculated for wet milling producers and dry milling producers in each state that produces ethanol, based on the cost of corn in each state, since this is the most germane segment of production costs. By-product credit prices and all other expenses were assumed to remain constant for all states (see Appendix I).

It appears that low-cost ethanol from the Caribbean, entering the U.S. duty-free, would be the first volume of ethanol available for use by California. Minnesota's ethanol requirements (13,500 b/d) are first supplied by the low cost wet milling producers in Minnesota and Iowa, and California's ethanol requirements are then supplied with the remainder of ethanol production in the U.S., based on order of production costs. In general, California is first supplied by the lower-cost wet milling operations, and then, as the price of ethanol rises to cover the costs of production of dry milling operations, ethanol is supplied by these producers.

In summary, then, the intermediate term supply curve for ethanol delivery to California is

constructed by determining the ethanol volumes that come on line as the price of ethanol rises to meet the cost of ethanol production in each state (which, in turn, is determined by the cost of corn in each state).

The estimates of state corn prices and production volumes, as well as estimated costs of production for wet milling and dry milling operations in each state, are detailed in Appendix H and I. Wet milling and dry milling ethanol producers are identified, where possible in Appendix A, Table A-2.

4.1.4.2

Long Term Cost Estimates
Ethanol Without Tax Credits

The prices at which ethanol will be delivered to California in the long term in the absence of the Federal subsidy are calculated similarly to the intermediate term case without the Federal subsidy. That is, the net production cost for ethanol was determined by state, using differential corn costs.

As stated above, according to the USDA data used in this study, those states with the largest volumes of corn production tend to be the states with the lowest corn costs. In the long term scenario, which allows for new grassroots ethanol plant construction, ethanol production will migrate to those states that have the lowest corn costs (and thus the lowest net ethanol production costs). In addition, ethanol production will be limited to wet-milling operations, which enjoy lower net production costs than dry milling operations due to the higher value of the by-products associated with wet milling. In other words, without the benefit of the Federal subsidy, which allows ethanol prices to remain higher than they would without the subsidy, producers will have to seek low-cost regions and production configurations (wet milling) in order to remain viable producers.

Thus, in the long run scenario, dry milling operations in the United States cease (these plants represent approximately 34,000 b/d of ethanol production today), due to their much higher net production costs. Wet milling survives in those states where facilities presently exist (Minnesota with 2,600 b/d of capacity, Nebraska with 10,100 b/d of capacity, Illinois with 33,300 b/d of capacity, Iowa with 25,400 b/d of capacity, and Indiana with 5,500 b/d of capacity). In order to replace the balance of ethanol lost by the shut-in of dry milling plants (33,700 b/d), new wet milling plants will probably be built in those states that offer state production incentives (generally this is in the form of a 20 cent/gallon subsidy up to a pre-determined volume of ethanol per year). The states that offer this subsidy are Kansas, Minnesota, South Dakota, and Nebraska. The 33,700 b/d of new wet milling production that replaces shut-in dry milling plants in the long run is assumed to be split evenly between these states.

The following are the long term net production costs and volumes of ethanol available from those states that will supply the fuel. In essence, these cost and volume relationships constitute the long run supply curve for ethanol delivered to California in the absence of the Federal ethanol subsidy:

State	Ethanol net	Existing wet	Long term	Long term

	production cost	**milling capacity**	**additions of wet milling capacity**	**capacity total**
South Dakota	$0.79	0	8,423	8,423
Minnesota	$0.82	2,609	8,423	11,032
Iowa	$0.85	25,440	0	25,440
Nebraska	$0.88	10,111	8,423	18,534
Indiana	$0.89	5,545	0	5,545
Illinois	$0.90	33,268	0	33,268
Kansas	$0.90	0	8,423	8,423
TOTALS:		76,973	33,691	110,664

4.2

ETBE Use In California (MTBE Ban In California Only)

The supply curves described in this section utilize analysis from the previous section regarding the cost estimates for ethanol. This is necessary since one of the main feedstocks for ETBE manufacture is ethanol. Therefore, cost estimates for ethanol (both with and without the tax credit) must be used to determine the cost of different quantities of ETBE.

4.2.1

California's ETBE Requirements

ETBE contains about 15.7% oxygen, and therefore about 12.7% ETBE is needed in a gallon of gasoline to achieve the 2.0 wt. % oxygen target. This study assumes that California consumes on average about 965,000 b/d of gasoline in the intermediate term. The amount of ETBE needed under the current regulations *for oxygen purposes only (not volume)* is therefore about 123,000 b/d to achieve a 2.0 wt. % oxygen level, and 165,000 b/d to achieve a 2.7 wt. % oxygen level. In the long term, California is assumed to demand 1.022 million b/d of gasoline. The amount of ETBE needed at this demand level is about 130,000 b/d to achieve a 2.0 wt. % oxygen level, and 175,000 b/d to achieve a 2.7 wt. % oxygen level.

4.2.2.

ETBE Availability

As stated in Section 2.2, the U.S. currently produces only a small quantity of ETBE, but capacity is estimated at about 53,000 b/d and could increase substantially if existing MTBE plants were converted to ETBE output. In addition, there is approximately 40,000 b/d of ETBE or MTBE/ETBE capacity outside North America. As explained below, however, it is unlikely that this foreign source of potential ETBE would be supplied to the California market.

4.2.3

ETBE Cost Estimates (Tax Credits Available)

The price/volume relationships analyzed below are found various tables and charts in Appendix M, Table M-7 and M-8. The prices and blending values of various petroleum products used in the analysis below are found in Appendix K. It is assumed that all subsidies including tax credits for blenders are in place throughout the country.

4.2.3.1.

ETBE Intermediate Term Cost Estimates

The cost of ETBE is highly dependent on the price of ethanol, since ETBE contains about 43% ethanol. ETBE producers supplying California, therefore, would require about 53,000 b/d of ethanol to manufacture 123,000 b/d of ETBE (123,000 times 0.43), and 71,000 b/d of ethanol to manufacture 165,000 b/d of ETBE. Increased demand for ETBE will necessarily increase demand for ethanol.

ETBE is produced by reacting .695 gallons of isobutylene with 0.43 gallons of ethanol, at a variable operating cost of 4.6 cents. Production costs therefore depend heavily on the price of ethanol, and alkylation economics (see Appendix D and Appendix K for blending values and production cost formulas).

The current tax codes allow the ETBE tax credit to be claimed by the blender and seller of gasoline containing ETBE. Therefore, the refiner using ETBE will claim the credit. Merchant producers of ETBE in the past have added a 23.2 cent/gallon surcharge on the market price of ETBE, which was then claimed by the purchaser of the ETBE as a tax credit.

It should be noted that although there is close to 40,000 b/d of existing ETBE or combined MTBE/ETBE production outside of North America (located in Brazil, Europe, and Saudi Arabia), imports of ETBE from foreign producers would not be eligible for the U.S. federal ethanol tax credit, which applies to domestically produced ethanol only. Therefore, it would be more economic for existing ether capacity in the U.S. to convert to ETBE production, so that purchasers of ETBE (refiners) could capture the subsidy.

The ETBE supply curve shown in Appendix D is built up in 5,000 b/d increments, each of which will require about 2,150 b/d of ethanol (5,000 b/d times 0.43 = 2,150 b/d). This ethanol would be bid away from other users around the country in the same fashion as was described in the intermediate term ethanol supply curve above.

It is assumed that the intermediate term allows for both the relatively quick and inexpensive conversion of fixed-bed MTBE plants to ETBE production, as well as the more expensive and time consuming conversion of MTBE plants employing catalytic distillation process technology.

The input price of ethanol for ETBE production at these facilities is derived from the price/volume relationships developed for the intermediate term ethanol supply curve described in Section 4.1.3.1. The input price in this case, however, is the market price for ethanol, or the breakeven price of ethanol plus 54 cents (the delivered price to California, which is 15 cents/gallon higher, is not used).

The refinery model used in this study assumes that in the California-only ban of MTBE scenario, the 13,000 b/d of existing in-situ ether plants in California will continue to manufacture MTBE and TAME for gasoline exported to Arizona/Nevada, and will not convert to ETBE production.

The first volumes on the supply curve, therefore, are approximately 18,000 b/d of ETBE supplied from the Western Canadian ether plant that is converted to ETBE production. This will require about 7,700 b/d of ethanol, which is delivered to Canada with a transportation cost of 15 cents/gallon. Finished ETBE is delivered to California with a transportation cost of 3 cents/gallon.

The rest of ETBE delivered to California comes from the Gulf Coast, where most U.S. ether production is located. Presumably, enough capacity in the Gulf would be converted from MTBE production to ETBE production. Again, the ethanol input price for ETBE produced in the Gulf Coast is read from the intermediate term ethanol supply curve from Section 4.1.3.1, with an 8 cent/gallon transportation cost from the Midwest to Gulf Coast. Finally a 9 cent/gallon transportation cost is assessed for delivery of ETBE from the Gulf Coast to California (this transportation cost includes a 1 cent/gallon surcharge for water soluble products).

The supply curve for ETBE is built up in this fashion as volumes arrive from the Gulf. As MTBE production is switched to ETBE production, ether capacity is tied up in the U.S., reducing MTBE supply in the U.S. However, because reduction MTBE supply is matched barrel by barrel with a reduction in MTBE demand (MTBE is banned in California), there is no net reduction in the U.S. MTBE supply/demand balance until MTBE capacity is switched to ETBE capacity above and beyond the reduction in U.S. MTBE demand. At this point, blenders of oxygenated gasoline or RFG gasoline outside California will begin facing a shortage of MTBE, and look to alternative oxygenates to satisfy their oxygen requirements.

The reduction in MTBE demand caused by its ban in California is estimated at approximately 105,000 b/d. Therefore, tying up ether production in excess of 105,000 b/d will result in a net reduction of U.S. MTBE supply, and blenders will begin valuing ethanol, the next most available alternate oxygenate, for its oxygenate value. Therefore, the input value of ethanol for ETBE production will rise.

To determine this input price of ethanol as ethanol is valued as an oxygenate, it is useful to determine where ethanol would potentially be demanded in the U.S. Wintertime oxygenated gasoline will be required in several states, notably New Mexico, Arizona, Washington, Oregon, Utah, Nevada, Montana and Colorado. Using data from the U.S. Energy Information Agency's 1997 *Petroleum Marketing Annual*, potential ethanol demand at 2.7 wt.% oxygen level was estimated, as well as potential ethanol demand at 2.0 wt. % oxygen level (RFG areas). EIA gasoline demand was multiplied by 0.077 or 0.057 depending on the oxygen content of the region:

State	**Actual oxygenated/RFG gasoline demand**	**Equivalent ethanol demand**	**Ethanol breakeven value**
New Mexico	7,688	592	88.8
Utah	2,388	184	83.1
Nevada	16,338	1,258	84.5
Montana	590	45	84.6
Oregon	22,114	1,703	87.6
Arizona	23,933	1,843	88.7
Washington	36,350	2,799	88.9
Colorado	33,455	2,576	90.4
Texas (RFG)	282,040	16,076	94.5
Texas (oxy)	8,243	635	94.9
New Hampshire (RFG)	22,443	1,279	97.6
Connecticut (RFG)	88,933	5,069	97.7
Rhode Island (RFG)	35,693	2,034	97.9

The ethanol that would be potentially demanded by these states will also be valued differently in

each state, depending on relative gasoline prices and MTBE prices. Using the equation presented in Section 4.1.3.1, set up for valuing ethanol as an oxygenate at a 2.7 wt. % oxygen level in states where oxygenated wintertime gasoline is required, and 2.0 wt. % in states were RFG gasoline is required, ethanol values were calculated for the volume potentially demanded by each state. The same methodology as in Section 4.1.3.1 was used to determine state by state gasoline rack prices, (see Appendix C for this data). The above table ranks several states in order of the value they assign to ethanol, and the potential volumes of ethanol they would demand.

On the point on the ETBE supply curve where MTBE capacity is crowded out (105,000 b/d), the curve begins reading the above breakeven levels of ethanol plus 54 cents/gallon, plus 8 cents transportation to the Gulf Coast. For example, as the ETBE supply curve reaches 120,000 b/d, 15,000 b/d of MTBE demand is crowded out. This increment of 15,000 b/d of ETBE demand will require 6,500 b/d of ethanol. On the table above, 6,500 b/d of cumulated ethanol demand equates to an ethanol value of 88.9 cents/gallon.

In sum, then, the volumes of ethanol required as feedstock for ETBE production in the U.S. once ETBE production surpasses 105,000 b/d on the supply curve are valued at their oxygenate value. The price/volume relationship is determined by potential volumes of ethanol demand from states that will require oxygenates for wintertime oxygenated gasoline.

4.2.3.2

ETBE Long Term Cost Estimates

In the long term scenario, ETBE production facilities are either converted from MTBE capacity or grassroots ETBE facilities are built.

As in the intermediate term case, the long term supply curve for ETBE delivered to California is highly dependent on the price of ethanol, since ETBE contains about 43% ethanol. The difference in this case is that the input cost of ethanol is determined by the long term supply curve for ethanol. All other costs are the same as in the intermediate term case.

The refinery model used in this study assumes that in the California-only ban of MTBE scenario, the 13,000 b/d of existing in-situ ether plants in California will continue to manufacture MTBE and TAME for gasoline exported to Arizona/Nevada, and will not convert to ETBE production.

The first block of ETBE supplied to California is assumed to be based in Canada. This includes the 19,000 b/d of new capacity coming on line (see Appendix A, Table A-1), for a total of 37,000 b/d of ether capacity in Canada. The transportation cost for ethanol delivered to Canada is assessed at 15 cents/gallon, and the transportation cost for finished ETBE delivered to California is 3 cents/gallon.

The remainder of ETBE delivered to California is supplied from ether capacity in the Gulf Coast. Ethanol input costs to the Gulf Coast are also read off the long term supply curve for ethanol, and an 8 cent/gallon transportation cost is added to the delivered cost of ethanol in the Gulf Coast. A 9 cent/gallon transportation cost is added to the delivered cost of ETBE from the Gulf Coast to California (including the surcharge for water soluble materials).

In the long term, it is assumed that MTBE capacity is not crowded out as it was in the intermediate term, because the long term allows for additional MTBE plants to be built.

4.2.4

ETBE: Loss of Tax Credit

The most significant element of the supply curves for ETBE without the ethanol tax credit is that the delivered price to California will contain the 23.2 cent/gallon pro-rated price of ethanol instead of netting it out.

4.2.4.1

ETBE Intermediate Cost Estimates Without Tax Credit

Determining the supply curve for ETBE without the ethanol subsidy requires reading off the already-established intermediate term price curve for unsubsidized ethanol (see Appendix M, Table M-5).

Again, it is assumed that the intermediate term allows for switching both types of MTBE process technology to ETBE production, except in California, where it is assumed that ether units will manufacture MTBE and TAME for gasoline exported to Arizona and Nevada.

The first 18,000 b/d of ETBE supplied to California are produced from Canadian MTBE capacity converted to ETBE production. The input cost for ethanol reads the intermediate supply curve for ethanol without tax credits (see Section 4.1.4.1). This Canadian ETBE capacity will require approximately 7,700 b/d of ethanol, which be supplied from volumes of ethanol imported from the Caribbean, as this ethanol can be imported at lowest cost (83 cents/gallon) and is therefore economic even without the tax credit.

The remainder of California's ETBE requirements are supplied from ether capacity in the Gulf Coast. The ethanol input cost is read from the curve described in Section 4.1.4.1, with a transportation cost of 8 cents/gallon. A transportation cost of 9 cents/gallon is added to the delivered cost of ETBE to California from the Gulf Coast (this includes the 1 cent/gallon surcharge for water soluble materials.

As explained in Section 4.2.3.1, after 105,000 b/d of MTBE capacity is converted to ETBE production, ether production capacity in the U.S. that would normally supply blenders outside of California with MTBE is tied up. This reduces net oxygenate supplies in the U.S., and results in a higher supply curve for ethanol, as ethanol is now valued for its oxygenate value.

However, the elimination of the ethanol subsidy causes production of ethanol only at prices which are above the oxygenate values of ethanol determined in Section 4.2.3.1. In other words, the lowest price at which ethanol can be economically produced, 98 cents/gallon, is greater than the breakeven oxygenate values which ethanol would be bid to, as former blenders of MTBE turned to ethanol, as determined in Section 4.2.3.1 (97.9 cents/gallon, ex subsidy). Therefore, the ETBE curve described in this section continues to read its input cost of ethanol from the curve described

in Section 4.1.4.1 (the intermediate term supply curve for ethanol absent the Federal subsidy).

4.2.4.2

ETBE Long Term Cost Estimates Without Tax Credit

Determining the long term supply curve for ETBE without the ethanol subsidy requires reading off the already-established long term price curve for unsubsidized ethanol (see Appendix M, Table M-6).

The first block of ETBE supplied to California is assumed to be based in Canada. This includes the 19,000 b/d of new capacity coming on line (see Appendix A, Table A-1), for a total of 37,000 b/d of ether capacity in Canada. The first 7,700 b/d of ethanol required as feedstock for this ETBE capacity is supplied from the Caribbean at a delivered cost of 83 cents/gallon, and volumes above this are delivered from the Midwest at a transportation cost of 15 cents/gallon. The transportation cost for finished ETBE delivered from Canada to California is 3 cents/gallon.

The remainder of ETBE delivered to California is supplied from ether capacity in the Gulf Coast. Ethanol input costs to the Gulf Coast are also read off the long term supply curve for ethanol, and an 8 cent/gallon transportation cost is added to the delivered cost of ethanol in the Gulf Coast. A 9 cent/gallon transportation cost is added to the delivered cost of ETBE from the Gulf Coast to California (including the surcharge for water soluble materials).

There is no ether production tied up in the long term, as more MTBE facilities can be built in the long term, or cheaper MTBE can be imported. See Appendix M, Table M-10 for price/volume relationships.

4.3

TAME Use in California (MTBE Ban in California Only)

Only the intermediate supply curve for TAME delivery to California needs to be considered. Long term supply is determined in the refinery modeling conducted for the "mixed oxygenate case" for the various scenarios in the overall study.

There are no policy assumptions other than a ban on MTBE that would affect the supply curve for TAME.

4.3.1

California's TAME Requirements

TAME contains about 15.7% oxygen, and about 12.4% TAME is needed in a gallon of gasoline to achieve the 2.0 wt. % oxygen target. This study assumes that California consumes on average about 965,000 b/d of gasoline in the intermediate term. The amount of TAME needed under the current regulations *for oxygen purposes only (not volume)* is therefore about 120,000 b/d to achieve a 2.0 wt. % oxygen level, and 161,000 b/d to achieve a 2.7 wt. % oxygen level. In the long term, California is assumed to demand 1.022 million b/d of gasoline. The amount of TAME needed at this demand level is about 127,000 b/d to achieve a 2.0 wt. % oxygen level, and 171,000 b/d to achieve a 2.7 wt. % oxygen level.

4.3.2

TAME Availability

As stated in Section 2.4, the U.S. currently has capacity to produce about 23,000 b/d of TAME. In addition, there is about 24,000 b/d of TAME capacity outside the U.S. Capacity can only be increased by building new TAME units at refineries that do not currently have units. Additional TAME capacity in the long term will be determined by the refinery modeling conducted for the "mixed oxygenate case" for various scenarios in this study. These additional supplies will come from the U.S. or abroad, as estimated through refinery modeling.

4.3.3

TAME Cost Estimates

The supply curve analyzed below is found in Appendix M, Table M-11.

4.3.3.1

TAME Cost Estimates, Intermediate Term

As explained above, TAME is feedstock limited, and existing capacity cannot be expanded. In the intermediate term, therefore, the supply curve is bounded at 47,000 b/d, which represents the total capacity available in the world.

In the intermediate term, California CARB RFG blenders would have to outbid other users of the limited volumes of TAME in order to secure oxygenate supply and comply with California and Federal oxygen regulations. A breakeven price for TAME needs to be determined, above which current users of TAME will switch to alternate oxygenates such as MTBE, ethanol, etc.

In order to make these breakeven comparisons, TAME needs to be valued correctly.

TAME's value will depend on the cost of MTBE, the cost of pool gasoline, and the cost of octane and RVP. Using a volume percentage of TAME and MTBE that averages the amount needed to reach a 2.0 wt % oxygen level (12.4% and 11.0% respectively) and the amount needed to reach a 2.7 wt. % oxygen level (16.7% and 14.8% respectively), TAME's value can be expressed using the following equation[4]:

$$P_{TAME} = (.871P_{B\text{-}MTBE} - .8545P_{B\text{-}TAME} + .129P_{MTBE})/0.1455$$

Where

P_{TAME} = Price of TAME
$P_{B\text{-}MTBE}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with MTBE
$P_{B\text{-}TAME}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with TAME
P_{MTBE} = Price of MTBE

In order to determine the relevant price/volume relationships for TAME supply, blocks of outside supply are identified, and breakeven TAME values are determined to attract these volumes away from their markets. Transportation costs are then added from the various regions around the world that have TAME capacity and could ship the product to California. Those regions are: the U.S. Gulf Coast and East Coast, Europe (both Northwest Europe and the Mediterranean), the Caribbean, and South Africa.

The first volume of TAME supplied to California is 5,100 b/d of TAME produced within the California refining system. This TAME is valued at 85.3 cents/gallon, using an MTBE price of 89.4 cents/gallon and a pool gasoline price of 69.6 cents/gallon.

The second block of TAME supplied to California is roughly 7,100 b/d produced in Europe. This TAME is valued at 77.3 cents/gallon, based on an MTBE price of 81.9 cents/gallon and a pool gasoline price of 56.5 cents/gallon. The price of MTBE and pool gasoline in Europe was determined by applying a differential (taken from ESAI's price database) to the Gulf Coast pool gasoline and MTBE prices used in this study. A transportation cost of 8.2 cents/gallon and 8.9 cents/gallon were used for delivery of TAME to California, depending on TAME production locations in Northwest Europe or Mediterranean Europe.

[4] This equation is similar to the equation used in Section 4.1.3.1, which is derived in Appendix B. The co-efficients have been set up for blending with TAME instead of ethanol.

Approximately 9,400 b/d of TAME will be supplied to California through the Caribbean. This TAME is valued at 80.9 cents/gallon, based on Gulf Coast MTBE and pool gasoline prices of 85.4 cents/gallon and 62 cents/gallon.

The Gulf Coast will provide up to 15,600 b/d of TAME, at a cost of 80.9 cents/gallon, based on an MTBE price of 85.4 cents/gallon and a pool gasoline price of 62 cents/gallon.

Approximately 1,500 b/d of TAME will be available from Asia. TAME is valued at 84.5 cents/gallon, based on MTBE and pool gasoline prices of 89.4 cents/gallon and 62.1 cents/gallon. Approximately 2,600 b/d of TAME will be supplied from the U.S. East Coast (Delaware), at a cost of 84.6 cents/gallon, based on MTBE and pool gasoline prices of 89.4 cents/gallon and 63.5 cents/gallon. Finally, South Africa can provide up to 5,600 b/d of TAME, at a cost of 84.7 cents/gallon, based on MTBE and pool gasoline prices of 89.4 cents/gallon and 64 cents/gallon.

Since TAME is produced by refineries in relatively small volumes for internal use, rather than merchant sales, handling and transportation costs are relatively high compared to oxygenates that are produced for merchant sales. A 10 cent/gallon handling/shipping surcharge was added to TAME's delivery price to California in order to ensure that TAME is not delivered cheaper than the base case for MTBE delivery to California, as TAME is not presently imported into the state.

The price/volume relationships and transportation costs are shown below:

Region	**Volume of TAME (b/d)**	**TAME value (cents/gallon)**	**Transportation and handling to California (cents/gallon)**	**Delivered price TAME to California (cents/gallon)**
California	5,100	85.31	10	95.31
NWE	2,300	77.19	18.2	95.39
Med	4,784	77.25	18.9	96.15
Caribbean	9,350	80.94	15.7	96.64
Gulf Coast	15,610	80.91	18	98.91
Taiwan	1,500	84.47	17	101.47
Delaware	2,572	84.63	20	104.63
South Africa	5,603	84.68	20	104.68
TOTAL	46,819			

4.4

TBA (MTBE Ban in California Only)

The intermediate and long term supply curves for TBA delivered to California are described below. There are no policy assumptions other than a ban on MTBE that would affect the supply curve for TBA

4.4.1

California's TBA Requirements

TBA contains about 21.6% oxygen, and about 8.8% TBA is needed in a gallon of gasoline to achieve the 2.0 wt. % oxygen target. This study assumes that California consumes on average about 965,000 b/d of gasoline in the intermediate term. The amount of TBA needed under the current regulations *for oxygen purposes only (not volume)* is therefore about 85,000 b/d to achieve a 2.0 wt. % oxygen level, and 114,000 b/d to achieve a 2.7 wt. % oxygen level. In the long term, California is assumed to demand 1.022 million b/d of gasoline. The amount of TBA needed at this demand level is about 90,000 b/d to achieve a 2.0 wt. % oxygen level, and 121,000 b/d to achieve a 2.7 wt. % oxygen level.

4.4.2

TBA Availability

As stated in Section 2.5, there is nearly 60,000 b/d of TBA capacity in the world, with nearly 35,000 b/d located in the U.S. Most of this production is associated with propylene oxide production, and most (except for some chemical use) is currently converted to MTBE due to MTBE's higher octane value. TBA capacity can be increased by either converting MTBE units to TBA units or building new TBA units, although conversion of MTBE units is a more economic solution.

During the intermediate term, it is assumed that all MTBE units can be converted to TBA production, except for ether units in California, which are assumed to produce MTBE and TAME for blending in gasoline exported to Arizona and Nevada.

4.4.3

TBA Cost Estimates

The supply curves analyzed below are found in Appendix M, Tables M-12 M-13.

4.4.3.1

TBA Cost Estimates Intermediate Term

TBA production that exists today is mostly used for conversion to MTBE, as MTBE has a higher octane value. It is assumed that existing TBA plants would supply California with TBA if it were just as or more profitable to produce TBA as a final product instead of MTBE. In addition, California blenders will bid away TBA from those ether plants that have converted to TBA production by bidding the price of TBA above a breakeven level with other oxygenates. The intermediate supply curve for TBA delivered to California is therefore based on the prices required to induce existing TBA/MTBE plants to switch from MTBE to TBA production, and to bid away converted volumes from other blenders.

The first volumes of TBA supplied to California on the supply curve will be from the 18,000 b/d of MTBE production in Canada that would be converted to TBA production. TBA is 20% denser than MTBE, so that the 18,000 b/d of MTBE capacity will produce roughly 14,400 b/d of TBA. Using a volume percentage of TBA and MTBE that averages the amount needed to reach a 2.0 wt % oxygen level (8.8% and 11.0% respectively) and the amount needed to reach a 2.7 wt. % oxygen level (11.8% and 14.8% respectively), TBA's value can be expressed using the following equation[5]:

$$P_{TBA} = (.872P_{B\text{-}MTBE} - .897P_{B\text{-}TBA} + .129P_{MTBE})/0.103$$

Where

P_{TBA} = Price of TBA
$P_{B\text{-}MTBE}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with MTBE
$P_{B\text{-}TBA}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with TBA
P_{MTBE} = Price of MTBE

Using this equation, and the inputs of 85.4 cents/gallon for MTBE and 62 cents/gallon for pool gasoline, Canadian-produced TBA is valued at 80.6 cents/gallon. A transportation cost of 3 cents/gallon is assessed for delivery to California.

The second block of TBA supplied to California on the supply curve will be from approximately 66,000 b/d of MTBE production in the U.S. Gulf Coast that would presumably be converted to 55,000 b/d of TBA production. Using the equation above, with the inputs of 85.4 cents/gallon for MTBE and 62 cents/gallon for pool gasoline, Gulf Coast-produced TBA is valued at 84.6 cents/gallon. An 8 cent/gallon transportation cost is assessed for TBA delivered from the Gulf Coast to California.

The third block of TBA supplied to California on the supply curve will be volumes of MTBE production in the U.S. Gulf Coast that would be converted to TBA production. Using the equation above, with inputs of 85.4 cents/gallon for MTBE and 62 cents/gallon for pool gasoline, Gulf Coast produced TBA is valued at 84.1 cents/gallon, and delivered to California with an 8 cent/gallon transportation charge.

A value for TBA was derived for each region that could *currently* supply TBA as a finished product instead of upgrading it to MTBE (existing TBA/MTBE plants in Northwest Europe, Mediterranean, U.S. Gulf Coast, Russia). The TBA value was derived by estimating the

[5] This equation is similar to the equation used in Section 4.1.3.1, which is derived in Appendix B. The co-efficients have been set up for blending with TBA instead of ethanol.

market value required to make TBA more valuable as a finished product than it would be as a feedstock for MTBE production. The equation used for converting TBA to MTBE is as follows, on a liquid volume basis[6]:

$$0.8 \text{ TBA} + 0.34 \text{ methanol} = 1 \text{ MTBE}$$

With this equation, TBA's value is tied to the market value of MTBE and methanol. For the purposes of this study, different MTBE values were used for each region that produces TBA, while methanol prices were held constant (61.2 cents/gallon), due to a lack of publicly available international data on methanol prices. In this way, a breakeven price of TBA for TBA production around the world was determined, and a freight cost was added to arrive at a delivered cost to California.

Thus, the next available block of TBA available to California on the supply curve will be 21,000 b/d of TBA produced in Europe. The MTBE price in Europe used for this study is 81.9 cents/gallon, which is the Gulf Coast price (85.4 cents/gallon) minus a differential based on ESAI's price database. In addition, a 10 cent/gallon handling/transportation cost is assigned TBA, due to the fact that TBA is presently produced for internal use (upgrading to MTBE), rather than merchant sales. It is assumed that, similar to the case of TAME production, handling and transport costs will be higher than the case of volumes of MTBE sold by a merchant producer. Using the above equation that ties TBA's value to MTBE and methanol, TBA will be available from Europe at 84.6 to 85.3 cents/gallon, depending on the transportation cost from Northwest Europe or the Med Europe.

The remaining supply of TBA delivered to California will originate from existing TBA production in the U.S. Gulf Coast. Using a Gulf Coast MTBE price of 85.4 cents/gallon, TBA would be valued at 84 cents/gallon, and delivered to California at $1.02/gallon.

The price/volume relationship for existing TBA production is as follows:

TBA supply region	**TBA capacity (volume available)**	**MTBE value (cents/gallon)**	**TBA value (cents/gallon)**	**Transportation and handling cost to California (c/g)**	**Delivered cost to California (c/g)**
Canada (converted)	14,400	85.4	80.6	3	83.6
Gulf Coast (converted)	54,600	85.4	84.1	8	92.1
NW Europe	10,400	81.9	76.4	18.2	94.6
Med Europe	10,600	81.9	76.4	18.9	95.3
US Gulf Coast	34,800	85.4	80.7	18	98.7

Again, the Gulf Coast price of MTBE is assumed to be unaffected in this scenario, since the decline in demand is met barrel for barrel by the decline in supply (as MTBE is converted to TBA production).

[6] This equation supplied by ARCO Chemical Company.

4.4.3.2

TBA Cost Estimates Long Term

Estimates of long term TBA supply costs are based on MTBE production economics, which are very similar to TBA production economics. The difference is that TBA operating costs are higher by 20%, due to the fact that for every barrel of MTBE produced, only 0.8 barrels of TBA are produced.

The long term supply curve for TBA was constructed by taking the production costs from the long term MTBE supply curve base case, and factoring in a 20% increase in operating costs. Long term TBA supply is assumed to come from areas such as Canada and the Middle East that have low-cost MTBE/TBA production economics. At the higher end of the supply curve, existing TBA production in the U.S. Gulf Coast will supply TBA to California based on the equation explained above (0.8 TBA + .34 Methanol = 1 MTBE). The extra 10 cent/gallon transportation/handling surcharge is not assumed to be present in the long run.

Section 5.

SCENARIO: *MTBE BANNED IN UNITED STATES*

SUPPLY COST ESTIMATES FOR ALTERNATIVE OXYGENATES

The second scenario in this study posits that MTBE is banned not only in the state of California, but nation-wide. Different policy assumptions under this scenario are then examined with respect to their effect on the cost of alternative oxygenates within the marketplace. With the exception of the policy assumption of HR630 passing (which would allow California refiners the option of using no oxygenate at all during the summer season), other oxygenates are needed by California refiners to comply with federally and state mandated minimum oxygen levels in CARB RFG.

The supply curves examined below are estimates of the cost of alternate oxygenates delivered to California in the event of a nation-wide ban on MTBE. As in the case of a California ban only, the cost of the following alternate oxygenates will be analyzed: ethanol, ETBE, TAME, and TBA. And, as in the case of a California ban only, the only policy assumptions (or combination of policy assumptions) that would have an impact on the shape of the supply curves will be those involving removal of tax credits for ethanol and ETBE. This is because while HR 630 may reduce the ultimate volume of oxygenate (whether MTBE, ethanol, ETBE, etc), it will not change the slope of the supply curve. Likewise, granting ethanol a 1 psi RVP waiver may result in a higher amount of ethanol consumed in California, but it will not change the slope of the supply curve. Since tax credit issues change the ultimate price of ethanol and ETBE, this is the only policy assumption that will result in a different supply curve for these oxygenates.

The refinery model used in this study allows for California ether capacity to be converted to ETBE and TBA production under the scenario of a U.S.-wide ban of MTBE.

5.1

Ethanol Use in California (U.S. MTBE Ban)

Two sets of supply curves need to be considered for the alternative oxygenate ethanol. The first set of supply curves considered will represent the price of ethanol with current tax regulations in place (i.e., gasoline blenders are eligible for up to a $.54/gallon tax credit for ethanol in blends of up to 10%, and a pro-rated tax credit for blends of less than 10%, such as 7.7% and 5.7%), both for the intermediate term and the long term. The second set of supply curves will represent the price of ethanol without the tax credit, both for the intermediate term and the long term.

5.1.1

U.S. and California Ethanol Requirements (U.S.-Wide MTBE Ban)

California's ethanol requirements in the case of a U.S.-wide ban of MTBE are the same as in the case of a California-only ban of MTBE.

5.1.2

Ethanol Availability in the U.S. and the World

Currently, the U.S. produces about 80,000 b/d of ethanol, and imports an small amount occasionally from Central America. We estimate the current on-line capacity in the U.S. and Canada to be about 111,000 b/d. Therefore, ethanol producers are only producing at about 70% of capacity and there is about 30,000 b/d of spare capacity that can be used to supply the country.

Brazil is the largest producer of ethanol in the world, and has a capacity of about 260,000 b/d. However, the U.S. would be unable, under present circumstances, to import much ethanol from Brazil. Brazil has mandated that all gasoline sold in the country contain 24% ethanol. Brazil's average gasoline consumption is about 300,000 b/d, and therefore the amount of mandated ethanol use is 66,000 b/d. In addition, however, 4 million of Brazilian cars are built to run on 100% ethanol (hydrous ethanol). The ethanol used to fuel these cars must therefore be considered dedicated ethanol, or ethanol that cannot be pulled from Brazil for use outside the country. This amounts to about 148,000 b/d of dedicated ethanol supply.

Therefore, in reality, there is very little Brazilian ethanol that can be supplied to the U.S. market, since 214,000 b/d (148,000 b/d + 66,000 b/d) is currently dedicated or mandated for use in Brazil. During the immediate term, at most about 30,000 b/d of surplus ethanol could presently be supplied to the U.S. market as surplus Brazilian ethanol. While the number of cars running on 100% ethanol in Brazil is declining, overall gasoline consumption has been rising very rapidly, approaching close to 10% growth in 1997. Therefore, lower ethanol use in Brazil by dedicated vehicles is being offset to a large degree by the growth of the gasoline pool. In addition, foreign ethanol that is not considered under the Caribbean Basin Initiative exemption is currently subject to a 54 cent/gallon tariff. This tariff is presumed to remain in place for the purposes of this study.

France, Italy, and Spain together produce about 30,000 b/d of excess wine ethanol from their combined wine industries. This ethanol, however, would also be subject to the tariff of $.54/gallon applied against foreign produced biomass ethanol. So would other beverage grade ethanol, available in Asia and the FSU.

There are also quantities of synthetic ethanol available on the world market. However, this ethanol would not be eligible for the tax credit, as it is not a biomass fuel, and would need to be diverted from its end use as chemical feedstock.

5.1.3

Ethanol Cost Estimates (U.S. Ban of MTBE)

The price/volume relationships analyzed below are found in Appendix M, Table M-14 and M-15. It is assumed that all subsidies including tax credits for blenders are in place throughout the country.

5.1.3.1

Ethanol Cost Estimates, Intermediate Term, U.S. Ban on MTBE

The U.S. consumes on an annual basis approximately 2.7 million b/d of reformulated gasoline, and approximately 230,000 b/d of oxygenated gasoline for wintertime carbon monoxide programs. Excluding California, which in the intermediate term is assumed to demand 965,000 b/d of reformulated gasoline in this study, the U.S. consumes 1.71 million b/d of RFG. Excluding Minnesota, which consumes 79,000 b/d of oxygenated gasoline due to its year-round 2.7 wt. % oxygen requirement, the U.S. consumes approximately 154,000 b/d of oxygenated wintertime gasoline. Thus, in the event of a U.S. ban on MTBE, the U.S., excluding California and Minnesota, would need to find enough oxygen to satisfy about 1.86 million b/d of gasoline that needs to be either oxygenated for reformulation purposes or for wintertime oxygen purposes.

In order to accommodate a sensitivity for the refining modeling section of the study that assumes California gasoline blenders can blend ethanol up to a 3.5 wt. % oxygen level, the supply curve for ethanol delivered to California must supply up to nearly 100,000 b/d of ethanol (965,000 b/d of gasoline at 3.5 wt. % oxygen is equivalent to a 10% ethanol blend, or 96,500 b/d of ethanol).

In the event of a U.S.-wide ban of MTBE, gasoline blenders outside of California will see ethanol as a substitute for MTBE. Therefore, in the intermediate term, California will need to compete for this limited ethanol supply with these outside blenders. As ethanol is bid above its breakeven value, outside blenders will seek other substitutes, such as TAME and TBA. Presumably, MTBE capacity will be converted to TBA output in order to supply this demand.

In order to make these breakeven comparisons, ethanol needs to be valued correctly. In Section 4.1.3.1 (ethanol delivered to California in the intermediate term under a California only ban of MTBE), breakeven values were calculated for blenders of ethanol within each state. Ethanol's value depended on whether it was being used as an oxygenate in oxygenated

gasoline in that state, or whether it was being blended in gasohol as a gasoline extender.

In this section, a similar calculation is made. Instead of determining breakeven values needed to bid ethanol away from ethanol blenders in each state, breakeven values are calculated to determine the price necessary to outbid non-Californian blenders of RFG and oxygenated wintertime gasoline. In the case of a U.S. ban on MTBE, gasoline blenders outside California will be seeking alternate oxygenates in the marketplace to satisfy their oxygen blending requirements. These blenders will value ethanol as an oxygenate, and will bid ethanol prices above the typical Midwest gasohol value. Therefore, in order to secure delivery of ethanol to California, blenders in California will need to bid ethanol above the breakeven oxygenate value for each outside blender of RFG or wintertime oxygenated gasoline.

In Section 4.1.3.1, ethanol's value as an oxygenate depended on the cost of MTBE, the cost of octane and Reid Vapor Pressure (RVP). In this case, however, MTBE has been banned, eliminating it as a useful benchmark against which to price ethanol. Ethanol's value will be determined, therefore, by other substitutable oxygenates, such as TAME and TBA.

The value of TAME and TBA can be assumed to be equal to MTBE's market value (85.4 cents/gallon in this study), minus an adjustment for octane differences. Using an octane price of 0.7 cents/octane number, TAME is worth 3.5 cents/gallon less than MTBE (MTBE's octane level of 110 minus TAME's octane level of 105 multiplied by the octane price). TBA is worth 7 cents/gallon less than MTBE (MTBE's octane level of 110 minus TBA's octane level of 100 multiplied by the octane price). TAME's market value is therefore calculated as 81.9 cents/gallon, and TBA's value is calculated as 78.4 cents/gallon. In addition, a 4 cent/gallon differential was added to the TBA/TAME price in Padds I, II, IV, and V to account for similar differentials from Gulf Coast prices that exist today in the MTBE market.

With a benchmark value against which to value ethanol (the averaged price of TAME and TBA), breakeven prices can be calculated by RFG or oxygenated gasoline areas around the U.S.

To determine the breakeven level for ethanol in states requiring RFG gasoline the following equation is used, with the co-efficients set up to account for the volumes of ethanol and TBA/TAME required to achieve a 2.0 wt. % oxygen level [7]:

$$P_{EOH} = (0.894\ P_{B\text{-}TAME/TBA} - 0.943\ P_{B\text{-}EOH} + 0.106\ P_{TAME/TBA} - C_{EOH})/0.057$$

Where

P_{EOH} = Price of ethanol
$P_{B\text{-}TAME/TBA}$ = Averaged price of reformulated blendstock for oxygenate blending (RBOB) with TAME and TBA.
$P_{B\text{-}EOH}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with ethanol
$P_{TAME/TBA}$ = Averaged price of TAME and TBA

[7] This equation is similar to the equation used in Section 4.1.3.1, which is derived in Appendix B. In this equation and the one following it, the co-efficients for TBA/TAME is an average of the volumes required to blend TBA and TAME to a 2.0 wt. % oxygen level, or a 2.7 wt. % level.

C_{EOH} = Any costs associated with blending ethanol

In states where oxygen is needed for blending in wintertime oxygenated gasoline, a similar equation is used, with the co-efficients set up to account for the volumes of ethanol and TBA/TAME required to achieve a 2.7 wt. % oxygen level:

$$P_{EOH} = (0.858\ P_{B\text{-}TAME/TBA} - 0.923\ P_{B\text{-}EOH} + 0.143\ P_{TAME/TBA} - C_{EOH})/0.077$$

The price of the RBOBs used in the above equations is dependent on the price of pool gasoline (see Appendix B for derivation). Since gasoline prices differ in each state, ethanol will be valued differently according to its gasoline market. Rack gasoline price data from the U.S. Energy Information Agency's *Petroleum Marketing Annual* publication were used to determine gasoline prices for all states that consume reformulated or oxygenated gasoline. Prices were adjusted for use in this study by basing them on the price of pool gasoline used in the study (62 cents/gallon) and then adding a differential based on the relative prices found in each state. For example, Indiana's rack price for gasoline was 1.5 cents/gallon higher than that of Mississippi, which had the lowest U.S. rack price; therefore, for the purposes of this study, the pool price for Indiana is 63.5 (62 plus 1.5).

Using the formulas expressed above, breakeven ethanol values were determined for each state that blends oxygen for RFG or oxygenated gasoline. The state-level incentives for ethanol use that exists in several states, namely South Dakota, Ohio, Missouri, and Illinois, does not effect the breakeven ethanol values here, since the oxygenate breakeven values rise above the gasohol break even values, even with the additional incentives factored in.

Using historical data for RFG and oxygenated gasoline sales in each state (source: U.S. Energy Information Agency 1997 *Petroleum Marketing Annual*), it is possible to determine the volume of ethanol that would be required to satisfy each state's oxygen requirement. Volumes of reformulated gasoline were multiplied by 5.7% to calculate potential ethanol volumes demanded for RFG gasoline at 2.0 wt. % oxygen level. Volumes of oxygenated gasoline were multiplied by 7.7% to calculate potential ethanol volumes demanded for oxygenated gasoline at 2.7 wt. % oxygen level.

The potential ethanol volumes (b/d) demanded by each state that requires RFG or oxygenated gasoline and price (cents/gallon) at which ethanol would be valued in each state are listed below:

State	**RFG Demand**	**Oxygenated Mogas demand**	**Potential Ethanol Demand**	**Ethanol Value**
New Mexico		7,688	592	84.7
Utah		2,388	184	86.8
Nevada		16,338	1,258	88.1
Montana		590	45	88.2
Oregon		22,114	1,703	91.0
Arizona	75,714	23,933	6,159	92.0
Washington		36,350	2,799	92.2
Colorado		33,455	2,576	93.6
Texas	282,040	8,243	16,711	95.2
New Hampshire	22,443		1,279	98.3

Connecticut	88,933	5,069	98.5
Rhode Island	35,693	2,034	98.6
Massachusetts	170,648	9,727	98.9
New Jersey	265,057	15,108	98.9
Maine	32,076	1,828	99.2
New York	192,302	10,961	100.2
Delaware	24,671	1,406	100.8
Illinois	169,755	9,676	101.1
Maryland	118,507	6,755	101.4
Wisconsin	43,902	2,502	101.5
Kentucky	31,071	1,771	101.7
Pennsylvania	89,138	5,081	101.8
Indiana	25,110	1,431	102.5
Virginia	129,588	7,387	102.6

The supply curve for ethanol delivered to California under a U.S.-wide ban of MTBE is built up by using the above volumes, which represent the amount of ethanol that blenders outside California would potentially demand unless the price was bid above a level at which they value ethanol.

Even if 100,000 b/d of ethanol was bid away from the rest of the country by California (in the case of the entire state blending to a 3.5 wt. % oxygen level), the rest of the U.S. could satisfy its oxygen requirements by a combination of leftover ethanol capacity, TAME, TBA, and additions to ethanol capacity.

U.S. RFG demand excluding California is estimated at about 1.71 million b/d. U.S. oxygenated gasoline demand excluding Minnesota is estimated at about 154,000 b/d. With up to 100,000 b/d of ethanol delivered to California, this would leave 11,000 b/d of spare capacity plus 7,700 b/d of ethanol imported from the Caribbean, for a total of about 19,000 b/d. This would account for approximately 328,000 b/d of RFG gasoline demand at 2.0 wt. % oxygen level (5.7% ethanol). Total world TAME capacity of nearly 47,000 b/d would account for approximately 378,000 b/d of RFG demand at 2.0 wt.% oxygen level (12.4% TAME). And total world TBA capacity of nearly 60,000 b/d would account for approximately 677,000 b/d of RFG demand at 2.0 wt.% oxygen level (8.8% TBA). Total RFG demand satisfied by these remaining oxygenates equals 1.38 million b/d, leaving 327,000 b/d of US RFG demand. In addition U.S. oxygenated gasoline demand (154,000 b/d) remains unsatisfied.

The remaining RFG demand of 327,000 b/d would require 19,000 b/d of ethanol at 2.0 wt.% oxygen level, while oxygenated gasoline demand of 154,000 b/d would require 12,000 b/d of ethanol at 2.7 wt.% oxygen level. It is assumed that this 31,000 b/d of ethanol capacity required to satisfy the remainder of U.S. oxygen requirements could be supplied by additions to existing ethanol capacity. The larger ethanol producers would most likely be the best candidates for this type of expansion, and would add to capacity as the price of ethanol increased, according to the supply curve.

5.1.3.2

Ethanol Cost Estimates, Long Term, U.S. Ban on MTBE

The methodology for determining the long term supply curve for ethanol under the U.S.-wide MTBE ban is similar to the case of the long term supply curve under a California-only ban, as explained in Section 4.1.3.2. In addition to the ethanol projects already planned, new producers will enter the market in the long term, attracted by higher prices for ethanol in the intermediate term and increased demand caused by a switch to ethanol consumption in California and the U.S. during the intermediate term.

The long term scenario assumes that the entire country uses ethanol in addition to the approximately 58,000 b/d to 102,000 b/d that would be produced to supply California's needs. Assuming that approximately 91% of ethanol will continue to be processed with corn feedstock, and that approximately 2.6 gallons of ethanol are produced from a bushel of corn, this increased demand will require additional feedstocks of 311 to 547 million bushels of corn per year.

In a long term time period, this additional corn can be expected to be supplied in response to demand. Additional corn production is expected to respond to the long term supply elasticity of price for corn (the percentage change in corn price divided by the percentage change in supply of corn), as explained in Section 4.1.3.2. Using this elasticity value of 0.3, prices for corn were calculated at various volumes of ethanol supplied to the market. For the purposes of this study, a baseline of $2.60/bushel was used.

In addition, bio-mass ethanol from other agricultural sources would probably be used. Since very little commercial capacity of bio-mass production exists today, and thus very little data on production costs are available, it is assumed that the production costs will be similar to corn-based ethanol.

As in Section 4.1.3.2, additional ethanol production is expected to result in a large increase in the supply of by-products, such as distiller's dried grains (DDG), gluten feed and gluten meal. It expected that the price of these by-products will decline in response to the long term supply elasticities for these products. The same byproduct elasticities used in Section 4.1.3.2, are used in this section.

Using these figures, it is possible to calculate supply elasticities for the by-products of ethanol production, and therefore determine the price of DDG, gluten feed, and gluten meal at various volumes of ethanol supplied to the market in the long term.

By determining the long term price of corn and the long term price of ethanol by-products, net production costs are calculated at various volumes of ethanol. All other fixed and variable costs besides corn cost and by-product prices were held constant.

In the long term scenario, ethanol prices are expected to decline to their marginal cost of production as calculated above. Since most production will still be located in the large corn-producing states, the transportation cost of 15 cents/gallon remains.

The calculations for determining the long term costs of corn and by-products are shown in Appendix J, and the formulas for determining the production costs for ethanol producers is explained in Appendix E.

5.1.4

Loss of Tax Credit

The following section estimates intermediate and long term cost of ethanol delivered to California in the absence of Federal subsidy, in the form of a 54 cent/gallon of ethanol tax credit.

The approach used for determining the supply curve for ethanol delivered to California in the absence of a Federal subsidy is to estimate the pattern of supply and use of ethanol, given the loss of the ethanol tax and with no California ban of MTBE, i.e., the current regulatory situation, but with no ethanol tax break. As is explained below, this study assumes that little or no ethanol use will continue. The supply curve for delivery of ethanol to California is then constructed by estimating the price necessary to induce ethanol plants to resume operation.

5.1.4.1

Ethanol Intermediate Term Cost Estimates: No Tax Credit, U.S. Ban on MTBE

In the event of a U.S.-wide ban of MTBE, blenders outside California would look to alternate oxygenates such as ethanol, TBA and TAME to satisfy their oxygen requirements. As explained in Section 5.1.3.1 (ethanol delivered to California with tax credits available and a U.S. ban of MTBE), California blenders will compete with blenders outside the state of California for ethanol supplies. In Section 5.1.3.1, the price was bid to a breakeven level that was equal to ethanol's oxygenate value from state to state. As the price of ethanol was bid above this calculated breakeven price, blenders outside California turned to TBA and TAME as alternatives, leaving ethanol to be delivered to California.

In this case, without the federal 54 cent/gallon subsidy, ethanol will not be produced unless its price rises above production costs. As explained in Section 4.1.4.1, these production costs can be expected to vary state-by-state depending on corn costs found in each state. In general, these ethanol production costs will be higher than the cost of the alternative oxygenates, TBA and TAME. Thus, as the price of ethanol rises to its production costs, blenders outside California will turn to TBA and TAME before ethanol, as TBA and TAME will be cheaper.

The methodology for constructing the supply curve for ethanol delivered to California absent the federal subsidy under a U.S. ban of MTBE results in the same curve as ethanol delivered to California absent the federal subsidy under a California-only ban of MTBE. Under a U.S. ban of MTBE, blenders outside California requiring oxygenates for oxygenated or RFG gasoline will use a combination of TAME, TBA and ethanol. These outside blenders will consume TBA and TAME first, as the cost for these oxygenates will be lower than the price that ethanol must reach in order to induce production from even the lowest cost producers.

Therefore, the supply curve for unsubsidized ethanol under a U.S.-wide ban of MTBE is identical to that of unsubsidized ethanol under the California-only ban of MTBE. Due to the fact that under a U.S.-wide ban of MTBE, blenders outside California can satisfy their oxygen requirements with

a combination of TBA, TAME and ethanol, California blenders will only have to bid the price of ethanol up to its production costs in each ethanol-producing state in order to secure supplies.

5.1.4.2

Ethanol Long Term Cost Estimates: No Tax Credit, U.S. Ban on MTBE

In the event of a U.S.-wide ban of MTBE, blenders outside California would look to alternate oxygenates such as ethanol, TBA and TAME to satisfy their oxygen requirements. As explained in Section 5.1.3.1, California blenders will compete with these blenders outside California for ethanol supplies. In Section 5.1.3.1, the price was bid to a breakeven level that was equal to ethanol's oxygenate value from state to state. As the price of ethanol was bid above this calculated breakeven price, outside blenders turned to TBA and TAME as alternatives.

In this case, without the federal 54 cent/gallon subsidy, ethanol will not be produced unless its price rises above production costs. As explained in Section 4.1.4.1, these production costs can be expected to vary state-by-state depending on corn costs found in each state. In the long term, as explained in Section 4.1.4.2, it is expected that low-cost wet milling ethanol producers will migrate to low-cost corn regions.

In general, even ethanol production costs for wet milling producers in low-cost corn regions will be higher than the cost of the alternative oxygenates, TBA and TAME. Thus, as the price of ethanol rises to its production costs, blenders outside California will turn to TBA and TAME before ethanol, as TBA and TAME will be cheaper.

The methodology for constructing the long term supply curve for ethanol delivered to California absent the federal subsidy under a U.S. ban of MTBE results in the same long term curve as ethanol delivered to California absent the federal subsidy under a California-only ban of MTBE. Under a U.S. ban of MTBE, blenders outside California requiring oxygenates for oxygenated or RFG gasoline will use a combination of TAME, TBA and ethanol. These blenders outside California will consume TBA and TAME first, as the cost for these oxygenates will be lower than the price that ethanol must reach in order to induce production from even the lowest cost producers.

5.2

ETBE Use in California (U.S. MTBE Ban)

As in Section 4.2, which considered a California-only ban on MTBE, in the case of a U.S. ban on MTBE, two sets of supply curves need to be considered for the alternative oxygenate ETBE: that of ETBE delivered to California with the ethanol subsidy intact in the intermediate and long term, and that of ETBE delivered to California without the subsidy in the intermediate and long term. Since one of the main feedstocks for ETBE is ethanol, the supply curve for ethanol (both with and without the tax credit) must be used to determine the cost of different quantities of ETBE.

5.2.1

California's ETBE Requirements (U.S.-wide MTBE Ban)

California's ETBE requirements in the case of a U.S.-wide ban of MTBE are the same as in the case of a California-only ban of MTBE.

5.2.2

ETBE Availability

As stated in Section 2.2, the U.S. currently produces only a small quantity of ETBE, but capacity is estimated at about 53,000 b/d and could increase substantially if existing MTBE plants were converted to ETBE output. In addition, there is approximately 40,000 b/d of ETBE or MTBE/ETBE capacity outside North America. As explained below, however, it is unlikely that this foreign source of potential ETBE would be supplied to the California market.

The refinery model used in this study assumes that in the scenario of a U.S.-wide ban of MTBE, the 13,000 b/d of existing in-situ ether plants in California will be converted to manufacture ETBE.

5.2.3

ETBE Cost Estimates (U.S. Ban of MTBE)

As described below, intermediate and long term supply curves for ETBE delivery are dependent on intermediate and long term ethanol costs under the scenario of a U.S.-wide MTBE ban. The supply curves described in this section are found in Appendix M, Table M-18 and Table M-19.

5.2.3.1

ETBE Cost Estimates, Intermediate Term, U.S. Ban on MTBE

The first block of ETBE available to California blenders will be ETBE produced at ether plants at California refineries. The ethanol input cost is taken from the intermediate term supply curve for ethanol under a U.S.-wide MTBE ban (see Appendix M, Table M-16), with a 15 cent/gallon transportation cost added. The formula for determining ETBE's cost is the same as in previous sections (see Appendix D).

The second block of ETBE available to California will be ETBE produced from converted MTBE capacity located in Canada. A 15 cent/gallon transportation cost is assessed to the ethanol input cost, and a 3 cent/gallon transportation cost is added for ETBE delivered from Canada to California.

The rest of California's ETBE supplies will be produced in the U.S. Gulf Coast, where most U.S. ether capacity is located. An 8 cent/gallon transportation cost is added (Midwest to Gulf Coast) for the ethanol input cost, and a 9 cent/gallon transportation cost (Gulf Coast to West Coast) is added to reach the delivered cost of ETBE to California (this includes the 1

cent/gallon surcharge for water soluble materials).

Under a U.S.-wide ban of MTBE, blenders outside California are assumed to use a combination of TBA, TAME and ethanol for their oxygenate requirements. At present world capacity, TAME and TBA volumes can only supply part of U.S. oxygenate demand excluding California, requiring either additional TBA conversion from existing MTBE capacity, or additional ethanol production. It is assumed that as the price of ethanol rises, many of the larger ethanol producers will make additions to capacity in order to supply blenders outside California.

The resulting supply curve is located in Appendix M, Table M-18.

5.2.3.2

ETBE Cost Estimates, Long Term, U.S. Ban on MTBE

The long term supply curve for ETBE delivered to California under a U.S.-wide ban of MTBE uses the same methodology as the intermediate term curve. The ethanol input costs, however, are read from the long term supply curve for ethanol (U.S. ban of MTBE), which is located in Appendix M, Table M-17.

The first block of 13,000 b/d of ETBE will be supplied from Californian refineries, using converted MTBE capacity. The ethanol input cost is assessed a 15 cent/gallon transportation cost (Midwest to West Coast).

The second block supplied to California is produced by 37,000 b/d of ETBE capacity in Canada (this includes present capacity and the 19,000 b/d of capacity currently under construction, listed in Appendix A, Table A-2). The ethanol input cost for this block of ETBE is assessed at 15 cents/gallon, and a 3 cent/gallon transportation cost is added for delivery of ETBE from Canada to California.

The remaining ETBE supplied to California is produced in the Gulf Coast, from converted MTBE capacity. A transportation cost of 8 cents/gallon is assessed for the ethanol input cost (Midwest to Gulf Coast) and a transportation cost of 9 cents/gallon is assessed for ETBE delivered to California (this includes the 1 cent/gallon surcharge for water soluble materials).

The resulting supply curve is located in Appendix M, Table M-19.

5.2.4

Loss of Ethanol/ETBE Tax Credit

The supply curves (intermediate and long term) for ETBE delivered to California without the Federal subsidy under a U.S. ban of MTBE are very similar to the cases under a California-only ban of MTBE, as explained below.

5.2.4.1

ETBE Cost Estimates, Intermediate Term, U.S. Ban on MTBE, No Tax Credits

The intermediate term supply curve for ETBE without the Federal subsidy is the same as the intermediate term supply curve for ETBE under a California only ban of MTBE, with the exception of the first 13,000 b/d of ETBE supplied to California (which, in the U.S. ban scenario, is supplied by California ether plants converted to ETBE production). This is because the intermediate term supply curve for unsubsidized ethanol, which is an input to the ETBE curve, is the same for the case of the U.S. ban of MTBE as it is for the case of the California-only ban of MTBE (see Section 5.1.4.1).

The resulting supply curve is located in Appendix M, Table M-20.

5.2.4.2

ETBE Cost Estimates, Long Term, U.S. Ban on MTBE, No Tax Credits

The long term supply curve for ETBE without the Federal subsidy is the same as the long term supply curve for ETBE under a California only ban of MTBE, with the exception of the first 13,000 b/d of ETBE supplied to California (which, in the U.S. ban scenario, is supplied by California ether plants converted to ETBE production). This is because the long term supply curve for unsubsidized ethanol, which is an input to the ETBE curve, is the same for the case of the U.S. ban of MTBE as it is for the case of the California-only ban of MTBE (see Section 5.1.4.2).

The resulting supply curve is located in Appendix M, Table M-21

5.3

TAME Use in California (U.S. MTBE Ban)

Only the intermediate supply curve for TAME delivery to California needs to be considered. Long term supply is determined in the refinery modeling conducted for the “mixed oxygenate case” for the various scenarios in the overall study.

There are no policy assumptions other than a ban on MTBE that would affect the supply curve for TAME.

5.3.1

California’s TAME Requirements (U.S.-wide MTBE Ban)

California’s TAME requirements in the case of a U.S.-wide ban of MTBE are the same as in the case of a California-only ban of MTBE.

5.3.2

TAME Availability

As stated in Section 2.4, the U.S. currently has capacity to produce about 23,000 b/d of TAME. In addition, there is about 24,000 b/d of TAME capacity outside the U.S. Capacity can only be increased by building new TAME units at refineries that do not currently have units. Additional TAME capacity in the long term will be determined by the refinery modeling conducted for the "mixed oxygenate case" for various scenarios in this study. These additional supplies will come from the U.S. or abroad, as estimated through refinery modeling.

5.3.3

TAME Cost Estimates (U.S.-Wide MTBE Ban)

The supply curves analyzed below are found in Appendix M, Table M-22.

5.3.3.1

TAME Cost Estimates, Intermediate Term

As explained above, TAME is feedstock limited, and existing capacity cannot be expanded. In the intermediate term, therefore, the supply curve is bounded at 47,000 b/d, which represents the total capacity available in the world.

In the intermediate term, California CARB RFG blenders would have to outbid other users of the limited volumes of TAME in order to secure supply and comply with California and Federal oxygen regulations. A breakeven price for TAME needs to be determined, above which current users of TAME will switch to alternate oxygenates such as MTBE, ethanol, etc.

In order to determine the make these breakeven comparisons, TAME needs to be valued correctly.

The methodology for building the supply curve for TAME under a U.S.-wide ban of MTBE is similar to the supply curve for TAME under a California-only ban of MTBE; however, in this case, since MTBE is banned throughout the U.S., a value for MTBE cannot be used to determine the value of TAME.

TAME's value will therefore depend on the value of ethanol, which, due to its availability, will be sought for oxygenate purposes in the case of a U.S. wide ban of MTBE. Therefore, under a U.S. ban of MTBE, TAME's value in a breakeven analysis will depend on the cost of ethanol, the cost of pool gasoline, and the cost of octane and RVP. Using a volume percentage of TAME and ethanol that averages the amount needed to achieve a 2.0 wt. % oxygen level (12.4% and 5.7% respectively) and a 2.7 wt. % oxygen level (16.7% and 7.7% respectively), TAME's value can be expressed using the following equation [8]:

[8] This equation is similar to the equation used in Section 4.1.3.1, which is derived in Appendix B. The co-efficients have been set up for blending with TAME instead of ethanol.

$$P_{TAME} = (.933P_{B\text{-}EOH} - .8545P_{B\text{-}TAME} + .067P_{EOH})/0.1455$$

Where

P_{TAME} = Price of TAME
$P_{B\text{-}EOH}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with ethanol
$P_{B\text{-}TAME}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with TAME
P_{EOH} = Price of ethanol

In order to determine the relevant price/volume relationships for TAME supply, blocks of outside supply are identified, and breakeven TAME values are determined to attract these volumes away from their markets.

Blenders in the U.S. will be competing for ethanol and TAME. At some breakeven price level, these blenders will use ethanol instead of TAME. Using the blocks of TAME available in the U.S. and elsewhere, volumes of ethanol can be determined to represent the amount of ethanol a blender in the U.S. would require as an alternative to consuming TAME. For example, the 5,100 b/d block of TAME supplied from California would be roughly equivalent to 2,300 b/d of ethanol. On the intermediate supply curve for ethanol delivery to California under the case of a U.S. ban of MTBE, ethanol's value at 2,300 b/d is 91 cents/gallon (see Appendix M, Table M-16). Using this value for ethanol results in a price of 78.2 cents/gallon for TAME. Ethanol values are determined for each block of TAME supply, using the equivalent ethanol/TAME volume:

TAME demanded by CA (cumulative and incremental)

5,100	7,400	12,184	21,534	37,144	38,644	41,216	etc.
5,100	2,300	4,784	9,350	15,610	1,500	2,572	etc.

Ethanol equivalent volume and price

2,346	3,404	5,605	9,906	17,086	17,776	18,960	etc.
91.0	91.0	92.0	92.0	95.2	95.2	95.2	etc.

Resulting TAME value

78.2	78.2	78.7	78.7	80.1	80.1	80.1	etc.

Once ethanol values have been determined to calculate TAME values, the supply curve is constructed, using the appropriate transportation costs from the production source to California (these transportation costs are the same as in Section 4.3.3.1).

As explained in Section 4.3.3.1, these volumes will be delivered to California with a surcharge of 10 cents/gallon, since TAME is produced by refineries in relatively small volumes for internal use, rather than merchant sales, and therefore handling and transportation costs are relatively high compared to oxygenates that are produced for merchant sales.

5.4

TBA Use in California (U.S.-Wide MTBE Ban)

Only two supply curves (intermediate term and long term) need to be considered for the alternative oxygenate TBA. There are no policy assumptions other than a ban on MTBE that would affect the supply curve for TBA.

5.4.1

US and California's TBA Requirements (U.S.-Wide MTBE Ban)

California's TBA requirements in the case of a U.S.-wide ban of MTBE are the same as in the case of a California-only ban of MTBE.

5.4.2

TBA Availability

As stated in Section 2.5, there is nearly 60,000 b/d of TBA capacity in the world, with nearly 35,000 b/d located in the U.S. Most of this production is associated with propylene oxide production, and most (except for some chemical use) is currently converted to MTBE due to MTBE's higher octane value. TBA capacity can be increased by either converting MTBE units to TBA units or building new TBA units, although conversion of MTBE units is a more economic solution.

The refinery model used in this study assumes that in the scenario of a U.S.-wide ban of MTBE, the 13,000 b/d of existing in-situ ether plants in California can be converted to manufacture TBA.

5.4.3

TBA Cost Estimates (U.S.-Wide MTBE Ban)

The supply curves analyzed below are located in Appendix M, Table M-23 and M-24.

5.4.3.1

TBA Cost Estimates, Intermediate Term

TBA production that exists today is mostly used for conversion to MTBE, as MTBE has a higher octane value. In the intermediate curve under the scenario of a California-only ban of MTBE, it was assumed that that existing TBA plants would supply California with TBA if it were just as or more profitable to produce TBA as a final product instead of MTBE. In addition, California blenders could bid away TBA from those ether plants that had converted to TBA production by bidding the price of TBA above a breakeven level with other oxygenates. An equation was used for that scenario that tied the price of TBA to MTBE and methanol, or tied TBA's value to the cost of MTBE and cost of pool gasoline and octane.

The scenario of a U.S.-wide ban of MTBE is complicated by the fact that there cannot be a value for MTBE. Blenders in the U.S. will be competing for the remaining oxygenates--TBA, TAME and ethanol. TBA's value will probably depend on the cost of the most available alternate oxygenate, ethanol. Therefore, under a U.S. ban of MTBE, TBA's value in a breakeven analysis will depend on the cost of ethanol, the cost of pool gasoline, and the cost of octane and RVP. Using a volume percentage of TBA and ethanol that averages the amount needed to achieve a 2.0 wt. % oxygen level (8.8% and 5.7% respectively) and a 2.7 wt. % oxygen level (11.8% and 7.7% respectively), TAME's value can be expressed using the following equation[9]:

$$P_{TBA} = (.933P_{B\text{-}EOH} - .897P_{B\text{-}TBA} + .067P_{EOH})/0.103$$

Where

P_{TBA} = Price of TBA
$P_{B\text{-}EOH}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with ethanol
$P_{B\text{-}TBA}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with TBA
P_{EOH} = Price of ethanol

Blenders in the U.S. will be competing for ethanol and TBA. At some breakeven price level, these blenders will use ethanol instead of TBA. Using the blocks of TBA available in the U.S. and elsewhere, volumes of ethanol can be determined to represent the amount of ethanol a blender in the U.S. would require as an alternative to consuming TBA. For example, the 10,200 b/d block of TBA from California (converted from 13,000 b/d of MTBE capacity) would be roughly equivalent to 6,600 b/d of ethanol. On the intermediate supply curve for ethanol delivery to California under the case of a U.S. ban of MTBE, ethanol's value at 6,600 b/d is 92 cents/gallon (see Appendix M, Table M-16). Using this value for ethanol results in a price of 77.4 cents/gallon for TBA. Ethanol values are determined for each block of TBA supply, using the equivalent ethanol/TBA volume (the first two blocks below represent TBA capacity in California and Canada, followed by 10,000 b/d increments of TBA capacity in the Gulf Coast):

TBA demanded by CA (cumulative and incremental)

10,160	24,560	34,560	44,560	54,560	64,560	74,560	84,560	etc.
10,160	14,400	10,000	10,000	10,000	10,000	10,000	10,000	etc.

Ethanol equivalent volume and price

6,604	15,964	22,464	28,964	35,464	41,964	48,464	54,964	etc.
92.0	95.2	95.2	95.2	98.5	98.9	98.9	98.9	etc.

Resulting TBA value

77.4	79.5	79.5	79.5	81.6	81.9	81.9	81.9	etc.

The supply curve is built up in this fashion, using the appropriate transportation costs from the production source to California.

[9] This equation is similar to the equation used in Section 4.1.3.1, which is derived in Appendix B. The co-efficients have been set up for blending with TBA against ethanol.

5.4.3.2

TBA Cost Estimates, Long Term

The long term supply curve for TBA under the scenario of a U.S.-wide ban of MTBE is identical to the case of the long term supply curve for the scenario of a California-only ban. In the long term, blenders outside of California are presumed to use ethanol, or TAME, and/or TBA for their oxygen requirements. California blenders are presumed not to compete with outside blenders for TBA as in the intermediate case scenarios.

Estimates of long term TBA supply costs are based on MTBE production economics, which are very similar to TBA production economics. The difference is that TBA operating costs are higher by 20%, due to the fact that for every barrel of MTBE produced, only 0.8 barrels of TBA are produced.

The long term supply curve for TBA was constructed by taking the production costs from the long term MTBE supply curve base case, and factoring in a 20% increase in operating costs. Long term TBA supply is assumed to come from areas such as Canada and the Middle East that have low-cost MTBE/TBA production economics. At the higher end of the supply curve, existing TBA production in the U.S. Gulf Coast will supply TBA to California based on the equation explained above (0.8 TBA + .34 Methanol = 1 MTBE).

Appendix A: Global Oxygenate Capacity

TABLE A-1: Global MTBE Capacity

Country/State	Company	Location	Status	Capacity (B/D)
NORTH AMERICA				
Delaware	Star Enterprises	Delaware City	Operating	2,000
New Jersey	Hess	Port Reading	Operating	1,500
Pennsylvania	Sun	Marcus Hook	Operating	2,500
Virgin Islands	Hess	St. Croix	Operating	4,000
Virginia	Amoco	Yorktown	Operating	700
Illinois	Marathon	Robinson	Operating	1,500
Indiana	Amoco	Whiting	Operating	2,800
Kentucky	Ashland	Catlettsburg	Operating	3,100
Michigan	Marathon	Detroit	Operating	1,100
Minnesota	Koch	Rosemont	Operating	1,500
Louisiana	Citgo	Lake Charles	Operating	2,700
Louisiana	Conoco	Lake Charles	Operating	1,500
Louisiana	Exxon	Baton Rouge	Operating	1,500
Louisiana	Exxon	Baton Rouge	Operating	7,000
Louisiana	Shell	Norco	Operating	6,000
Louisiana	Star Enterprises	Convent	Operating	2,500
Louisiana	Valero	Krotz Springs	Operating	2,100
Mississippi	Chevron	Pascagoula	Operating	2,400
Texas	ARCO Chemical	Channelview	Operating	28,500
Texas	Citgo	Corpus Christi	Operating	4,000
Texas	Deer Park Pet. Refinery	Deer Park	Operating	5,000
Texas	Diamond Shamrock	Sunray	Operating	2,000
Texas	Enron	LaPorte	Operating	15,000
Texas	Enterprise/Sun/Mitchell	Mt. Belvieu	Operating	16,000
Texas	Exxon	Baytown	Operating	3,000
Texas	Exxon	Baytown	Operating	7,000
Texas	Global Octane	Houston	Operating	12,500
Texas	Huntsman	Port Neches	Operating	10,000
Texas	Huntsman	Port Neches	Operating	15,000
Texas	Koch	Corpus Christi	Operating	1,100
Texas	Lyondell Petrochemical	Houston	Operating	2,000
Texas	Mobil	Beaumont	Operating	2,300
Texas	OxyChem	Chocolate Bayou	Operating	2,000
Texas	Phillips	Sweeny	Operating	3,000
Texas	Texas Petrochemical	Houston	Operating	18,000
Texas	Valero	Houston	Operating	1,500
Texas	Valero	Texas City	Operating	1,500
Texas	Valero	Corpus Christi	Operating	2,500
Texas	Valero	Corpus Christi	Operating	14,000
Wyoming	Coastal	Cheyenne	Operating	4,600
California	Atlantic Richfield	Watson	Operating	2,500
California	Chevron	El Segundo	Operating	2,000
California	Chevron	Richmond	Operating	2,000
California	Exxon	Benicia	Operating	4,000
California	Tosco	Martinez	Operating	2,200
Alberta	Neste Oy/Chevron	Edmonton	Operating	18,000
		TOTAL:	247,600	

Table A-1, con't: Global MTBE Capacity

Country	Company	Location	Status	Capacity (B/D)
LATIN AMERICA				
Argentina	Carboclor	Campana	Operating	500
Argentina	YPF	Lujan de Cuyo	Operating	1,000
Argentina	YPF	La Plata	Operating	1,000
Argentina	PGM	Ensenada	Operating	1,000
Brazil	Petrobras	Duque de Caxias	Operating	1,500
Brazil	Petrobras	Araucaria	Operating	1,709
Brazil	Petrobras	Paulinia	Operating	2,055
Brazil	Petrobras	Sao Jose dos Campos	Operating	1,514
Brazil	Petrobras	3 others	Operating	3,000
Brazil	Copene	Camacari	Operating	1,500
Brazil	Copesul	Bahia	Operating	2,000
Mexico	PEMEX	Cadereyta	Operating	800
Mexico	PEMEX	Salamanca	Operating	1,125
Mexico	PEMEX	Salina Cruz	Operating	1,500
Mexico	PEMEX	Tula	Operating	2,250
Mexico	PMI	Pajaritos	Operating	1,500
Venezuela	Corpoven	El Palito	Operating	2,675
Venezuela	Corpoven	Punta Cardon	Operating	2,175
Venezuela	Pequiven	Judibana	Operating	4,000
Venezuela	Super Octanos	Puerto La Cruz	Operating	12,500
			TOTAL	45,303
MIDDLE EAST				
Dubai	Dugas	Jebel Ali	Operating	12,500
Iran	National PC	Shiraz	Operating	1,000
Israel	Oil Ref's LTD	Ashdod	Operating	750
Israel	Dor	Haifa	Operating	1,000
Saudi Arabia	Ibn Sina	Al-Jubail	Operating	17,500
Saudi Arabia	Ibn Zahr I	Al-Jubail	Operating	12,500
Saudi Arabia	Ibn Zahr II	Al-Jubail	Operating	17,500
Saudi Arabia	SADAF	Al-Jubail	Operating	17,500
Saudi Arabia	Petromin-Mobil	Yanbu	Operating	2,500
			TOTAL	82,750
EUROPE				
Austria	OMV	Scwechat	Operating	1,600
Belgium	Fina	Antwerp	Operating	3,500
Finland	Neste Oy	Porvoo	Operating	3,000
France	Lyondell Petrochemical (formerly ARCO)	Fos-sur-mer	Operating	14,500
France	Elf	Feyzin	Operating	1,400
Germany	DEA	Heide	Operating	300
Germany	DEA	Wesseling	Operating	1,600
Germany	Erdoelfchemie	Cologne	Operating	750
Germany	Huels	Marl	Operating	3,750
Germany	OMW	Karlsruhe	Operating	3,250
Germany	VEB Pet. Komb. Schwedt	Schwedt	Operating	1,680
Greece	Hellenic Aspr. Ref.	Aspropyrgos	Operating	1,600
Greece	Motor Oils Hellas	Corinth	Operating	1,000

Table A-1, con't: Global MTBE Capacity

Country	Company	Location	Status	Capacity (B/D)
Italy	AGIP	Milazzo	Operating	1,500
Italy	AGIP	Sanazzaro	Operating	1,000
Italy	Anic	Gela	Operating	1,100
Italy	Ecofuel	Ravenna	Operating	3,250
Italy	Enichem/Anic	Gela	Operating	-
Italy	Selm	Priolo	Operating	1,000
Poland	Petrochimia Plock	Plock	Operating	1,500
Portugal	Neste Oy	Sines	Operating	1,250
Spain	Repsol	Tarragona	Operating	1,700
Spain	Repsol	Tarragona	Operating	1,300
Spain	CEPSA	Algeciras	Operating	1,000
Spain	Petronor	Bilbao	Operating	1,250
Spain	Repsol	La Coruna	Operating	1,200
Spain	Repsol	Puertollano	Operating	1,100
Spain	Repsol	Tarragona	Operating	1,300
Sweden	Statoil	Stenungsund	Operating	1,225
The Netherlands	Netherlands Refining	Europort	Operating	1,500
The Netherlands	Netherlands Refining	Rotterdam	Operating	3,500
The Netherlands	ARCO	Botlek	Operating	14,000
The Netherlands	DSM	Geleen	Operating	3,375
The Netherlands	Shell	Pemis	Operating	3,750
United Kingdom	Conoco	So. Killingholme	Operating	2,000
United Kingdom	Exxon	Fawley	Operating	3,000
United Kingdom	Lindsey Oil	Grimsby	Operating	2,500
			TOTAL	92,230
E. EUROPE / FSU				
Czech Republic	Chemopetrol	Kralupy	Operating	2,250
Hungary	Danube Petroleum Refinery	Szazholmbatta	Operating	1,250
Hungary	TIFO	Tiszauvaros	Operating	750
Lithuania	NAFTA (MNPB)	Mazeikiai	Operating	929
Romania	Astra SA	Pitesdi	Operating	852
Romania	Petromidia	Midia	Operating	852
Romania	Petrotel SA	Ploesti	Operating	510
Yugoslavia	FSK	Zrenjanin	Operating	950
Russia	Neftekhim	Nizhnekamsk	Operating	625
Russia	Moscow Oil Refinery	Moscow	Operating	1,000
Russia	Ornsk Nefteorgsintez	Omsk	Operating	1,750
Russia	Uralneftekhim	Chaikovski	Operating	2,788
Bulgaria	Naftochim	Burgas	Operating	1,859
			TOTAL	16,365
FAR EAST				
China	Hay Long	Daqing	Operating	250
China	Ningbo	Zhenhai	Operating	500
China	Quilo Petchem	Zibo	Operating	1,000
China	Shan Tong	Quilo	Operating	1,750
China	Sinopec	Dalian	Operating	250
China	Sinopec	Daqing	Operating	500

Table A-1, con't: Global MTBE Capacity

Country	Company	Location	Status	Capacity (B/D)
China	Sinopec	Maoming	Operating	1,000
China	Sinopec	Qilu	Operating	1,000
China	Sinopec	Zhenhai	Operating	1,000
China	Tan Gian	Liao	Operating	725
China	Fushin Petchem	Fushin	Operating	4,000
India	Bharat Petroleum	Bombay	Operating	1,000
Korea	Ssangyang Oil Refining	Onsan	Operating	500
Korea	Daelim	Yeochun	Operating	875
Korea	Honam Oil	Yeochun	Operating	470
Korea	Samsung/ Hyundai	Daesan	Operating	625
Korea	Yukong	Ulsan	Operating	1,200
Malaysia	Petronas	Kuantan	Operating	4,500
Malaysia	Kerteh			
Singapore	Singapore Refinery CPL	Pulau Merlimau	Operating	2,500
Singapore	PCS	Singapore	Operating	1,200
Taiwan	FPC	Kaohsiung	Operating	1,200
Taiwan	TASCO	Kaohsiung	Operating	3,150
Japan	Cosmo Oil	Sakai	Operating	1,500
Japan	Idemitsu Kosan	Chiba	Operating	2,500
Japan	Kashima Oil	Kashima	Operating	1,500
Japan	Nippon Petroleum	Negishi	Operating	1,700
Japan	Mitsui	Chiba	Operating	120
Japan	Sumitomo	Chiba	Operating	1,330
Japan	Tonen	Kawasaki	Operating	48
		TOTAL:	37,893	
		GLOBAL TOTAL:	522,141	

MTBE Projects at "Engineering/Construction" phase:

NORTH AMERICA

Trinidad & Tobago	Petroleum Co. Trinidad & Tobago Ltd	Pointe a Pierre	MTBE	929
Canada	Alberta BioClean	Ft. Saskatchewan	MTBE	19,000
			TOTAL:	19,929

LATIN AMERICA

Mexico	Petroleos Mexicanos	Cadereyta	MTBE	2,000
Brazil	Petrobras SA	Araucaria	MTBE	1,162
			TOTAL:	3,162

EUROPE

Sweden	Statoil Petrokemi SA	Stenungsund	MTBE	1,122
			TOTAL:	1,122

Table A-1, con't: Global MTBE Capacity

FSU/ E. EUROPE				
Romania	Petrotel SA	Teleajen	MTBE	467
Romania	Petromidia SA	Navodari	MTBE	818
FSU	Permnefteorgsyntez	Perm	MTBE	4,674
FSU	Kremenchug Oil Refinery	Kremenchug	MTBE	581
Country	**Company**	**Location**	**Status**	**Capacity (B/D)**
Romania	Arpechim SA	Pitesti	MTBE	467
Slovakia	Slovnaft a.s.	Bratislava	MTBE	1,052
FSU	Achinsk Refinery	Achinsk	MTBE	510
			TOTAL:	8,569
MIDDLE EAST				
Iran	National Petrochemical Co.	Bandar Imam	MTBE	14,022
Libya	Ras Lanuf Oil & Gas Co.	Ras Lanuf	MTBE	1,098
Kuwait	Kuwait Petroleum Co.	Mina Al-Ahmadi	MTBE	1,300
			TOTAL:	16,420
FAR EAST				
Singapore	Petrochem. Corp. of Singapore Pte. Limited	Merbau	MTBE	1,192
Taiwan	Formas Petrochemical Corp.	Mai Liao	MTBE	1,168
India	Indian Oil Corp. Ltd	Gujarat	MTBE	935
Taiwan	Formas Petrochemical Corp.	Hai Fong	MTBE	4,500
			TOTAL:	7,795
TOTAL GLOBAL ADDITIONS (engineering/under construction):				56,998

MTBE Projects at "Planning" or "Unknown" phase:

NORTH AMERICA				
USA	Tosco	Martinez, CA	MTBE	2,000
			TOTAL:	2,000
LATIN AMERICA				
Chile	Refineria de Petroleo Concon SA	Concon	MTBE	697
Mexico	Productos Ecologicos SV de CV	Morelos	MTBE	17,000
Venezuela	Cerasol	Paraguana, Falcon	MTBE	11,685
Brazil	Petro. Brasiliera	Cubatao	MTBE	1,696
Brazil	Petro. Brasiliera	Mataripe	MTBE	836
			TOTAL:	31,914
EUROPE				
Belgium	Statoil	Antwerp	MTBE	16,359
Spain	Elf Atochem SA	Algeciras	MTBE	1,052
Sweden	Norsk Hydro	Lysekil	MTBE	935
			TOTAL:	18,345

Table A-1, con't: Global MTBE Capacity

Country	Company	Location	Status	Capacity (B/D)
FSU/ E. EUROPE				
Lithuania	Ministry of the Petrochemicals Industry	?	MTBE	8,179
Croatia	Ina-Industrija Nafte d.d. Zagreb	Sisak	MTBE	900
FSU	Angarsk Petrochemical Co.	Angarsk	MTBE	2,804
FSU	Tobolsk Petrochem Combine	Tobolsk	MTBE	11,685
Romania	Petrobrazi SA	Ploiesti	MTBE	1,870
			TOTAL:	25,438
MIDDLE EAST				
Qatar	Qatar Fuels Additives Co.	Umm Said	MTBE	14,256
Saudi Arabia	Tahseen (Alujain Corporation, Ecofuel, Neste Oy)	Yanbu	MTBE	20,910
			TOTAL:	35,165
FAR EAST				
China	Chemical Auxiliary Agent Plant	Daqing	MTBE	327
South Korea	Hanwha Chemical Corp.	Yeo-Chun	MTBE	2,337
			TOTAL:	2,664
TOTAL GLOBAL ADDITIONS (planning/unknown status):				115,527

TABLE A-2: Global Ethanol Capacity

Country	Company	Location	CAPACITY MG/Y	B/D
NORTH AMERICA				
IL	ADM (wet mill)	Decatur	210.00	13,699
IL	ADM (wet mill)	Peoria	200.00	13,046
IA	ADM (wet mill)	Cedar Rapids	200.00	13,046
IA	ADM (wet mill)	Clinton	160.00	10,437
IL	Pekin Energy Co. (wet mill)	Pekin	100.00	6,523
IN	New Energy Co. of Indiana (wet mill)	South Bend	85.00	5,545
NE	Minnesota Corn Processors (wet mill)	Columbus	80.00	5,219
NE	Cargill (wet mill)	Blair	75.00	4,892
TN	A.E. Staley	Louden	42.00	2,740
MN	Minnesota Corn Processors (wet mill)	Marshall	40.00	2,609
IA	Cargill	Eddyville	30.00	1,957
NE	High Plains Corp. (dry mill)	York	30.00	1,957
NM	Giant Industries	Portales	30.00	1,957
NE	AGP (dry mill)	Hastings	30.00	1,957
NE	Chief Ethanol (dry mill)	Hastings	30.00	1,957
KS	Midwest Grain Products	Atchinson	26.00	1,696
NE	Nebraska Energy (dry mill)	Aurora	25.00	1,631
KS	High Plains Corp.	Colwich	20.00	1,305
UT	Self Enterprises	Garland	20.00	1,305
TX	Mapco Alcohol Fuel Inc.	Cactus	20.00	1,305
IA	Hubinger Co.	Keokuk	17.50	1,142
MN	Corn Plus	Winnebago	15.00	978
MN	Chippewa Valley Ethanol Company	Benson	15.00	978
IL	Midwest Grain Products	Pekin	12.00	783
MN	Ethanol2000	Bingham Lake	11.50	750
ND	Alchem	Grafton	10.00	652
MN	Al-Corn	Claremont	10.00	652
MN	Heartland Corn Products	Winthrop	10.00	652
MN	Minnesota Energy	Buffalo Lake	10.00	652
IA	Grain Processing Corporation	Muscatine	10.00	652
KY	Parallel Products	Louisville	10.00	652
KS	Reeve Agri-Energy	Garden City	10.00	652
SD	Heartland Grain Fuel	Aberdeen	8.00	522
SD	Broin Enterprises	Scotland	7.00	457
WA	Georgia-Pacific Corp	Bellingham	7.00	457
IA	Manildra	Hamburg	7.00	457
ID	J.R. Simplot	Caldwell	4.00	261
ID	J.R. Simplot	Heyburn	3.00	196
MN	Morris Ag Energy	Morris	5.00	326
WY	Brimm Energy Inc. (Wyoming Ethanol)	Torrington	5.00	326
CA	Golden Cheese of CA	Corona	3.00	196
CA	Parallel Products	Rancho Cucamonga	2.00	130
WI	ROI	Plover	2.00	130
MN	Kraft, Inc.	Melrose	1.50	98
CO	Merrick and Co.	Golden	1.50	98
IA	Permeate Refining	Hopkinton	1.50	98
MN	Minnesota Clean Fuels	Dundas	1.20	78
KS	ESE Alchohol	Leoti	1.10	72

TABLE A-2, con't: Global Ethanol Capacity

Country	Company	Location	CAPACITY MG/Y	B/D
TX	Jonton Alcohol	Edinburg	1.10	72
WA	Pabst Brewing	Olympia	0.70	46
WI	Farm Tech USA	Spring Green	0.50	33
IL	Vienna Correctional	Vienna	0.50	33
SD	Kor Ethanol	White	0.25	16
Canada	Commercial Alcohols	Chatham (Ontario)	39.63	2,585
Canada	Mohawk Oil	Minnedosa (Manitoba)	2.64	172
		TOTAL FUEL GRADE	1,699	110,836
North American Synthetic Ethanol:				
TX	Eastman	Longview	30	1,957
IL	Millenium Petrochemicals	Tuscola	50	3,262
TX	Union Carbide	Texas City	120	7,828
		TOTAL SYNTHETIC	200	13,046
		TOTAL ETHANOL (FUEL & SYNTHETIC)	1,899	123,883
LATIN AMERICA				
Brazil	Various	Center South Region		220,581
	Various	North-Northeast Region		34,466
	Various	of which: Sao Paolo State		168,882
		TOTAL:		255,047
MIDDLE EAST				
Saudi Arabia	SABIC *(Synthetic ethanol)*		111	7,238
		TOTAL:	111	7,238
EUROPE				
Poland	Man Alchohol			
France	Sugar Beet Distilleries	7 Locations	79	5,157
France	Sugar/Alcohol Complexes	16 Locations	47	3,094
France	SODES *(synthetic ethanol)*		32	2,063
Germany	Huls *(synthetic ethanol)*		60	3,916
Germany	Erdolchemie *(synthetic ethanol)*		20	1,305
Germany	Others		40	2,611
Sweden	Örnsköldsvik	Umea		
UK	BP Chemicals *(synthetic ethanol)*	Baglan Bay	58	3,807
UK	BP Chemicals *(synthetic ethanol)*	Grangemouth	52	3,372
Italy	Wine ethanol		53	3,446

TABLE A-2, con't: Global Ethanol Capacity

Country	Company	Location	CAPACITY MG/Y	B/D
(Europe, continued)				
Spain	Wine ethanol		53	3,446
		TOTAL:	494	32,218
E. EUROPE / FSU				
Russia	Various		660	43,075
ASIA/PACIFIC				
China	Various		998	65,128
India	Various		357	23,261
Thailand			13	862
Australia	Various		15	1,000
		TOTAL:	1,384	90,250
AFRICA				
S. Africa	SASOL *(Synthetic ethanol)*	Sasolburg	106	6,892
S. Africa		Secunda		
S. Africa		Sasol "Three" Plant		
S. Africa	National Chemical Products	Germiston	7	452
S. Africa	National Chemical Producs	Umgeni	7	452
S. Africa	Illovo Sugar		7	431
		TOTAL:	126	8,227
	TOTAL GLOBAL ETHANOL CAPACITY (INCLUDES SYNTHETIC):		8,584	559,938

Corn/Biomass Ethanol Projects at "Engineering/Construction" phase:

NORTH AMERICA				
MN	Central Minnesota Ethanol Coop (CMEC)	Little Falls	15	978
MT	American Agri-Technology	Great Falls	30	1,957
NE	Nebraska Nutrients Inc.	Sutherland	15	978
Canada	Commercial Alcohols	Tiverton, Ontario	6	396
Canada	Seaway Valley Farmer's Energy Cooperative Inc.	Cornwall, Ontario	15	948
		TOTAL:	81	5,258
FAR EAST				
India	Petron International	Mallanwan		514
Phillipines	Primofina Oleochemis Inc.	Jose Panganiban		653
		TOTAL:		1,167
		TOTAL GLOBAL ADDITIONS		

TABLE A-2, con't: Global Ethanol Capacity

		(engineering/under construction):		6,425

Corn/Biomass Ethanol Projects at "Planning" or "Unknown" phase:

NORTH AMERICA

IL	Adkins Energy Cooperative	Adkins	30	1,957
MN	CORN-er Stone Farmers' Cooperative	Luverne	15	978
MN	Exol Corporation - Agri Resources Co-op	Albert Lea	30	1,957
MN	RDO	Park Rapids	15	978
MN	Dawson Project	Dawson	20	1,305
MN	Renewable Oxygenates, Inc.	Madison	15	978
MN	South East Minnesota Ethanol Cooperative (SEMEC)	Preston	10	652
CA	Arkenol	Sacramento	12	783
CA	Quincy Library Group		20	1,305
CA	Gridley Project		12	783
Canada	Commercial Alcohols/ Quebec Grain Producers	Quebec	40	2,585
Canada	Commercial Alchohols	Chatham, Ontario	40	2,585
		TOTAL:	258	16,846

EUROPE

Sweden	Agroetanol AB	Norkopping	13	862
		TOTAL	13	862

	TOTAL GLOBAL ADDITIONS (planning/uknown status):	17,708

TABLE A-3: Global ETBE Capacity

Country	Plant	Location	Type	Capacity b/d
North America				
USA	Koch Refining Co.	Rosemount, MN	ETBE/MTBE	1,500
USA	Amoco Oil Co.	Yorktown, VA	ETBE/MTBE	700
USA	Amerada Hess	Virgin Islands	ETBE/MTBE	4,000
USA	ARCO Chemical	Corpus Christi, TX	ETBE/MTBE	12,000
USA	ARCO Chemical	Channelview, TX	ETBE/MTBE	28,500
USA	ARCO Products	Watson, CA	ETBE/MTBE	2,500
USA	Diamond Shamrock	Sunray, TX	ETBE/MTBE	2,000
USA	Marathon	Robinson, IL	ETBE/MTBE	1,500
			TOTAL:	52,700
Europe				
France	Elf Aquitaine	Feyzin	ETBE	1,742
Russia	Lukoil	Salavatnefteorgsintez	ETBE	3,000
Italy	Ecofuel	Ravenna	ETBE	1,800
France	Total	Dunkirk	ETBE	1,162
France	Ouest-ETBE	Gonfreville (Normandy)	ETBE	1,394
Poland	Petrochemia-MZRip	Plock	ETBE	1,859
			TOTAL:	10,957
Latin America				
Brazil	Petrobras (7 plants)	Various	MTBE/ETBE	10,000
			TOTAL:	10,000
Middle East				
Saudi Arabia	Sadaf		MTBE/ETBE	17,500
			TOTAL:	17,500
			GLOBAL TOTAL:	91,157

Projects at "Engineering/Construction" phase:

Canada	Alberta BioClean	Ft. Saskatchewan	MTBE/ETBE	19,000
France	Elf Antar		ETBE	1,800
			TOTAL:	20,800

TABLE A-4: Global TAME Capacity

Country	Company	Location	Type	Capacity
Europe				
France	Elf	Feyzin	TAME	1,250
Greece	Hellenic Aspropyrgos Refinery SA	Aspropyrgos	TAME	1,100
Italy	Praoil	Ragusa	TAME	1,200
Italy	Agip	Gela	TAME	1,234
Norway	Neste	Porvoo	TAME	1,000
UK	Lindsey Oil Refinery Ltd.	Killingholme South Humberside	TAME	1,300
			TOTAL:	7,084
Pacific				
Taiwan	Chinese Petroleum Corp.	Kaohsiung	TAME	1,500
			TOTAL:	1,500
North America				
USA	Chevron USA Products Co.	El Segundo, CA	TAME	2,600
USA	Chevron USA Products Co.	Richmond, CA	TAME	2,500
USA	Star Enterprise	Delaware City, DE	TAME	2,322
USA	Marathon Oil Co.	Robinson, IL	TAME	250
USA	Citgo Petroleum Corp.	Lake Charles, LA	TAME	3,420
USA	Star Enterprise	Convent, LA	TAME	3,150
USA	Diamond Shamrock Corp.	McKee, TX	TAME	2,140
USA	Valero Refining Co.	Corpus Christi, TX	TAME	5,000
USA	Kerr-McGee	Cotton Valley, TX	TAME	300
USA	Exxon	Baytown, TX	TAME	1,600
			TOTAL:	23,282
Latin America				
Mexico	Petroleos Mexicanos	Salina Cruz	TAME	1,396
Virgin Islands	Hess Oil Virgin Islands Corp	St. Croix	TAME	4,000
Venezuela	Corpoven SA	El Palito	MTBE/TAME	670
Argentina	YPF S.A.	La Plata	TAME	784
Venezuela	Lagoven		TAME	2,500
			TOTAL:	9,350
OTHER				
South Africa	SASOL Ltd.	Secunda	TAME	5,603
			TOTAL:	5,603
			GLOBAL TOTAL:	46,819

TABLE A-4, con't: Global TAME Capacity

TAME Projects at "Engineering/Construction" phase:

Country	Company	Location	Type	Capacity
India	Reliance Industries Ltd	Jamnagar	TAME	4,674
Venezuela	Lagoven SA	Judibana	TAME	8,300
FSU	Atyrau Refinery	Atyrau	MTBE/TAME	3,372
			TOTAL:	16,346

TABLE A-4: Global TBA Capacity

Country	Company	Location	Type	Capacity	
Europe					
France	Lyondell Petrochemical (fomerly ARCO)	Fos-Sur-Mer	TBA	10,800	
Netherlands	ARCO Chemical	Botlek	TBA	10,400	
		TOTAL:		21,200	
North America					
USA	ARCO Chemical	Channelview, TX	TBA	22,800	
USA	Huntsman Corp	Port Neches, TX	TBA	12,000	
		TOTAL:		34,800	
FSU					
Russia	Sintezkauchuk	Togliatti	TBA/MTBE (80/20 mix)		2,400
Russia	Kauchuka	Volzhski	TBA/MTBE (80/20 mix)		1,200
		TOTAL:		3,600	
		GLOBAL TOTAL:		59,600	

Appendix B: Derivation of Breakeven Equations

There are several equations used in this report that calculate the breakeven price level for different oxygenates. They are all based on the derivation of the same equation, which first appears in Section 4.1.3.1, in determining the supply curve for ethanol delivered to California in the intermediate term (California-only ban of MTBE). This equation was developed by Mathpro, Inc.

While the equation below is used for determining the breakeven price of ethanol, it can also be used to determine the breakeven level of TAME or TBA. The co-efficients (used to determine the percentage of oxygenate needed to achieve either a 2.0 wt. % or 2.7 wt. % oxygen level in gasoline) will change, as will the values for the RVP and octane levels of each oxygenate.

Derivation of Equation for the value of ethanol in oxygenated gasoline

1. Initial identity

$$.852\ P_{B\text{-}MTBE} + .148\ P_{MTBE} = .923\ P_{B\text{-}EOH} + .077\ P_{EOH} + C_{EOH}$$

Solve for P_{EOH} $\quad P_{EOH} = (.852\ P_{B\text{-}MTBE} - .923\ P_{B\text{-}EOH} + .148\ P_{MTBE} - C_{EOH}) / .077$

Where $P_{B\text{-}MTBE}$ = Price of reformulated blendstock for oxygenate blending (RBOB) for MTBE blending
$P_{B\text{-}EOH}$ = Price of reformulated blendstock for oxygenate blending (RBOB) for Ethanol blending
P_{MTBE} = Price of MTBE
P_{EOH} = Price of ethanol
C_{EOH} = Any costs associated with ethanol blending

Co-efficients set up for ethanol and MTBE blending to achieve a 2.7 wt % oxygen level in gasoline.

2. Equations for determining change in octane in RBOBs (pool octane assumed to be 89 octane)

A. MTBE: $.852\ O_{B\text{-}MTBE} + .148\ O_{MTBE} = 89$

$O_{B\text{-}MTBE} = (89 - .148\ O_{MTBE}) / .852$

$? O_{B\text{-}MTBE} = 89 - [(89 - .148\ O_{MTBE}) / .852]$

$? O_{B\text{-}MTBE} = 3.65$

Where $O_{B\text{-}MTBE}$ = Octane of RBOB used for blending MTBE (assumed equal to average pool octane)
O_{MTBE} = Octane of MTBE (110 octane)
$? O_{B\text{-}MTBE}$ = Reduction in octane of RBOB used for blending MTBE

Co-efficients of .852 and .148 set up for MTBE blending to achieve a 2.7 wt. % oxygen level

B. Ethanol: $.923\ O_{B\text{-}EOH} + .077\ O_{EOH} = 89$

$O_{B\text{-}EOH} = (89 - .077\ O_{EOH}) / .923$

$? O_{B\text{-}EOH} = 89 - [(89 - ..077\ O_{EOH}) / .923]$

$? O_{B\text{-}EOH} = 2.17$

Where $O_{B\text{-}EOH}$ = Octane of RBOB used for blending ethanol
O_{EOH} = Octane of Ethanol (115 octane)
$? O_{B\text{-}EOH}$ = Reduction in octane of RBOB used for blending ethanol

Co-efficients of .923 and .077 set up for ethanol blending to achieve a 2.7 wt. % oxygen level

2. Equations for determining change in RVP in RBOBs

A. MTBE: $.852\ RVP_{B\text{-}MTBE} + .148\ RVP_{MTBE} = RVP_{POOL}$

$? RVP_{B\text{-}MTBE} = RVP_{POOL} - [(RVP_{POOL} - .148\ RVP_{MTBE}) / .852]$

$? RVP_{B\text{-}MTBE} = - .174\ RVP_{POOL} + 1.39$

Where $RVP_{B\text{-}MTBE}$ = RVP of RBOB used for blending MTBE
RVP_{MTBE} = RVP of MTBE (8 RVP)
RVP_{POOL} = Pool gasoline RVP

B. Ethanol: $.923\ RVP_{B\text{-}EOH} + .077\ RVP_{EOH} = RVP_{POOL}$

$? RVP_{B\text{-}EOH} = RVP_{POOL} - [(RVP_{POOL} - .077\ RVP_{EOH}) / .923]$

$? RVP_{B\text{-}EOH} = - .083\ RVP_{POOL} + 1.50$

Where $RVP_{B\text{-}EOH}$ = RVP of RBOB used for blending ethanol
RVP_{EOH} = RVP of ethanol (18 RVP)
RVP_{POOL} = Pool gasoline RVP

3. Equations for estimating value of RBOBs

A. MTBE: $P_{B\text{-}MTBE} = P_{POOL} - (P_{OCT} * ? O_{B\text{-}MTBE} + P_{RVP} * ? RVP_{MTBE})$

B. Ethanol $P_{B\text{-}EOH} = P_{POOL} - (P_{OCT} * ? O_{B\text{-}EOH} + P_{RVP} * ? RVP_{EOH})$

Where $P_{B\text{-}MTBE}$ = Price of RBOB used for blending MTBE
$P_{B\text{-}EOH}$ = Price of RBOB used for blending ethanol
P_{POOL} = Price of pool gasoline
P_{OCT} = Price of octane
$? O_{B\text{-}MTBE}$ = Reduction in octane of RBOB used for blending MTBE
$? O_{B\text{-}EOH}$ = Reduction in octane of RBOB used for blending ethanol
P_{RVP} = Price of RVP

NOTE: These RBOB values are plugged into the initial identity, to solve for the price of ethanol.

Note on octane prices: In determining the breakeven level of ethanol (or other oxygenates) using the equations above, the following values for octane prices were used. In scenarios that covered oxygenates used in summer, octane was assumed to be worth 1 cent per octane number. For wintertime, octane was assumed to be worth 0.4 cents per octane number. In scenarios that covered oxygenate usage on a year-round basis, a simple average was used for the octane price (0.7 cents per octane number).

Note on RVP prices: In determining the breakeven level of ethanol (or other oxygenates) using the equations above, the following values for RVP prices were used. In scenarios that covered oxygenates used in summer, RVP was assumed to be worth -0.3 cents per RVP number (RVP value is negative in the summer because blenders need to limit RVP levels to comply with air quality regulations). For wintertime, RVP was assumed to be worth 0.3 cents per RVP number. In scenarios that covered oxygenate usage on a year-round basis, a simple average was used for the RVP value (0.0 cents per RVP number).

Derivation of Equation for the value of ethanol in regular gasoline ("gasohol")

The following equation, also developed by Mathpro, Inc., estimates the value of ethanol used as a gasoline extender in regular gasoline commonly known as gasohol. This equation is only used in Section 4.1.3.1, and calculates the price at which California blenders can bid ethanol away from blenders in States that use gasohol.

1. Initial identity:

$$P_{R\text{-}MOGAS} - P_{MOGAS} = P_{R\text{-}GASOHOL} - .9\, P_{B\text{-}EOH} - .1\, P_{EOH} - C_{EOH}$$

Solve for P_{EOH}

$$P_{EOH} = -(P_{R\text{-}MOGAS} - P_{MOGAS} - P_{R\text{-}GASOHOL} + .9\, P_{B\text{-}EOH} + C_{EOH}) / 0.1$$

Where P_{EOH} = Price of ethanol
$P_{B\text{-}EOH}$ = Price of RBOB used for blending ethanol
$P_{R\text{-}MOGAS}$ = Retail (pump) price of pool gasoline
$P_{R\text{-}GASOHOL}$ = Retail (pump) price of gasohol
P_{MOGAS} = Rack price of pool gasoline
C_{EOH} = Any costs associated with blending ethanol (assumed zero)

2. Equations for determining change in octane in ethanol RBOB (pool octane assumed to be 89 octane)

$$.9\, O_{B\text{-}EOH} + .1\, O_{EOH} = 89$$

$$O_{B\text{-}EOH} = (89 - .1\, O_{EOH}) / .9$$

$$? O_{B\text{-}EOH} = 89 - [(89 - .1\, O_{EOH}) / .9]$$

$$? O_{B\text{-}EOH} = 2.89$$

Where $O_{B\text{-}EOH}$ = Octane of RBOB used for blending ethanol
O_{EOH} = Octane of Ethanol (115 octane)
$? O_{B\text{-}EOH}$ = Reduction in octane of RBOB used for blending ethanol

Co-efficients of .9 and .1 set up for ethanol blending to achieve a 3.5 wt. % oxygen level commonly used in gasohol.

3. Equation for determining the retail price of gasohol

The pump price of gasohol is discounted from the pump price of regular pool gasoline since the consumer must be compensated for the fact that gasohol has a lower energy content than regular gasoline. This is due to the fact that ethanol's energy density is equal to roughly 3.55 million BTUs per barrel, whereas pool gasoline's energy density is equal to 5.25 million BTU's per barrel. Therefore, the ratio of ethanol to pool gasoline energy density is 0.68, which is used in the equation below, which states that gasohol's retail price must be equal to 90 percent of pool gasoline's retail price plus 10 percent of pool gasoline's retail price adjusted for the lower energy content due to the presence of the 10 percent ethanol blend:

$$P_{R\text{-}GASOHOL} = (.9 + .1*.68) * P_{R\text{-}MOGAS}$$

2. Equations for estimating value of ethanol RBOB:

$$P_{B\text{-}EOH} = P_{POOL} - (P_{OCT} * ?\ O_{B\text{-}EOH})$$

Where $P_{B\text{-}EOH}$ = Price of RBOB used for blending ethanol
P_{POOL} = Price of pool gasoline
P_{OCT} = Price of octane
$?\ O_{B\text{-}EOH}$ = Reduction in octane of RBOB used for blending ethanol

3. After solving for the value of the ethanol RBOB and the value of gasohol, these inputs are plugged into the initial identity above, and solved for the price of ethanol. Throughout this study, the cost of blending with ethanol is assumed to be zero, and there is assumed to be zero consumer bias against ethanol.

Appendix C: State by state gasoline price data

	Rack	Delta		Retail	State Tax	Fed tax	Pump price	Delta
Mississippi	64.5	-	Georgia	77.10	7.7	18.3	103.10	-
Louisiana	64.6	0.1	Oklahoma	76.50	17	18.3	111.80	8.70
Georgia	64.7	0.2	South Carolina	77.20	16.75	18.3	112.25	9.15
South Carolina	65.2	0.7	Michigan	78.40	15.88	18.3	112.58	9.48
North Carolina	65.3	0.8	Missouri	78.70	17.04	18.3	114.04	10.94
Alabama	65.3	0.8	Florida	83.20	12.8	18.3	114.30	11.20
Ohio	65.6	1.1	Indiana	80.80	15.8	18.3	114.90	11.80
Arkansas	65.6	1.1	Kansas	79.00	18.03	18.3	115.33	12.23
Tennessee	65.8	1.3	Arkansas	78.70	18.6	18.3	115.60	12.50
Florida	65.8	1.3	New Jersey	87.50	10.5	18.3	116.30	13.20
Texas	65.8	1.3	Texas	79.30	20	18.3	117.60	14.50
Oklahoma	65.9	1.4	Kentucky	83.40	16.4	18.3	118.10	15.00
Virginia	65.9	1.4	Iowa	80.40	20	18.3	118.70	15.60
Indiana	66	1.5	Alabama	83.20	18	18.3	119.50	16.40
Kansas	66.6	2.1	Louisiana	81.40	20	18.3	119.70	16.60
Missouri	66.6	2.1	Tennessee	80.10	21.4	18.3	119.80	16.70
West Virginia	66.6	2.1	Virginia	83.50	18.1	18.3	119.90	16.80
Michigan	66.7	2.2	Mississippi	83.70	18	18.3	120.00	16.90
Pennsylvania	66.8	2.3	Ohio	79.90	22	18.3	120.20	17.10
Kentucky	66.9	2.4	North Carolina	80.00	22.6	18.3	120.90	17.80
Wisconsin	67.2	2.7	West Virginia	83.60	20.5	18.3	122.40	19.30
Maryland	67.3	2.8	Illinois	84.40	20.1	18.3	122.80	19.70
Illinois	67.6	3.1	Vermont	88.90	16	18.3	123.20	20.10
Delaware	68	3.5	Delaware	82.70	23	18.3	124.00	20.90
Nebraska	68.1	3.6	Nebraska	80.80	25.4	18.3	124.50	21.40
Iowa	68.2	3.7	Pennsylvania	81.30	25.82	18.3	125.42	22.32
New York	68.7	4.2	New Hampshire	87.60	19.6	18.3	125.50	22.40
N. Dakota	69.2	4.7	New York	85.40	22.8	18.3	126.50	23.40
Vermont	69.3	4.8	S. Dakota	87.30	21	18.3	126.60	23.50
S. Dakota	69.5	5.0	Wisconsin	81.70	26.8	18.3	126.80	23.70
Maine	69.8	5.3	Maine	89.50	19	18.3	126.80	23.70
New Jersey	70.2	5.7	Maryland	85.10	23.5	18.3	126.90	23.80
Massachusetts	70.2	5.7	Massachusetts	88.30	21	18.3	127.60	24.50
Minnesota	70.3	5.8	N. Dakota	89.70	20.03	18.3	128.03	24.93
Rhode Island	70.5	6.0	Minnesota	90.00	20	18.3	128.30	25.20
Connecticut	70.7	6.2	Rhode Island	84.40	29	18.3	131.70	28.60
Colorado	70.7	6.2	Connecticut	87.20	36	18.3	141.50	38.40
New Hampshire	70.9	6.4						
Washington	72.3	7.8						
New Mexico	72.4	7.9						
Arizona	72.5	8.0						
Oregon	73.7	9.2						
Montana	77.0	12.5						
Nevada	77.1	12.6						
Utah	78.6	14.1						

Appendix D: Oxygenate production cost summary

MTBE from Normal Butane via Dehydrogenation

1.0 MTBE = 1.0 N-butane + .344 methanol + $.072/gallon operating cost

MTBE from Fluid Cat Cracker C4s:

1.0 MTBE = .8 isobutylene + .344 methanol + $.036/gallon operating cost

ETBE from Fluid Cat Cracker C4s:

1.0 ETBE = .695 isoobutylene + .431 ethanol + $.046/gallon operating cost

Appendix E: Derivation of Ethanol Production costs and producers' margins

Ethanol producers face differing cost structures depending on the feedstock costs (the price of corn for over 90 percent of ethanol producers) and the price producers receive for the by-products of corn milling (distillers' dried grains, corn gluten meal, corn gluten feed, corn germ, CO2, gypsum, etc.).

In order to determine a notional net production cost for wet milling and dry milling plants, historical data was used for the prices of corn, DDG, corn gluten meal and corn gluten corn. Due to a lack of historical data for corn germ and other minor by-products, these values were held constant. Operating and fixed costs were held constant. Ethanol producers are assumed to produce roughly 2.6 gallons of ethanol from each bushel of corn. Net production cost equals gross expenses minus gross credits.

Dry Milling Operation [10]

Expenses:

- Feedstock (corn) = Corn cost ($/bushel) / 2.6
- Other costs (energy, labor, depreciation, chemicals, fixed costs): .625 cents/gallon

Credits:

- Distillers' dried grains (DDG)= ((DDG cost, $/ton) / 2000 lbs) * (17.35 lbs/bushel of DDG) / 2.6
- Other byproducts = 1 cent/gallon (assumed constant)

Wet Milling Operation

Expenses:

- Feedstock (corn) = Corn cost ($/bushel) / 2.6
- Other costs (energy, labor, depreciation, chemicals, fixed costs): .51 cents/gallon

Credits:

- Corn gluten meal: ((gluten meal cost, $/ton) / 2000 lbs) * (2.8 lbs/bushel of corn) / 2.6
- Corn gluten feed: ((gluten feed cost, $/ton) / 2000 lbs) * (10 lbs/bushel of corn) / 2.6
- Corn germ: ((germ cost, $/ton) / 2000 lbs) * (4 lbs/bushel of corn) / 2.6
- Other byproducts = 1 cent/gallon (assumed constant)

[10] Notional cost structures for wet/dry milling producers provided by Arkenol, Inc.

Appendix F: Historical Prices for Ethanol Production

The following prices were used to construct historical ethanol net production costs using the notional formula supplied above. Historical price data for germ was not available; a constant value of $250/ton was used instead. All other prices provided by Hart's Publications.

	Ethanol Price $/gallon	**Corn Price $/bu**	**Corn Price $/gallon**	**DDG ($/ton)**	**Gluten Meal $/ton**	**Gluten Feed $/ton**	**Germ $/ton**
January-92	$1.18	$2.54	$0.98	$124.00	$270.63	$105.00	$250.00
February	$1.19	$2.62	$1.01	$125.13	$271.88	$107.50	$250.00
March	$1.20	$2.67	$1.03	$123.50	$277.50	$107.50	$250.00
April	$1.24	$2.56	$0.99	$117.13	$252.50	$108.50	$250.00
May	$1.26	$2.58	$0.99	$115.38	$245.00	$106.00	$250.00
June	$1.27	$2.63	$1.01	$115.38	$247.50	$108.50	$250.00
July	$1.28	$2.47	$0.95	$120.38	$245.63	$108.50	$250.00
August	$1.33	$2.29	$0.88	$123.00	$242.70	$108.50	$250.00
September	$1.34	$2.26	$0.87	$125.25	$264.38	$108.50	$250.00
October	$1.36	$2.17	$0.84	$125.98	$270.25	$106.50	$250.00
November	$1.38	$2.17	$0.83	$126.42	$267.38	$103.00	$250.00
December	$1.29	$2.43	$0.93	$128.44	$267.50	$106.00	$250.00
January-93	$1.19	$2.30	$0.88	$129.67	$288.33	$103.50	$250.00
February	$1.15	$2.25	$0.87	$131.50	$283.40	$96.00	$250.00
March	$1.14	$2.25	$0.86	$123.55	$296.00	$97.00	$250.00
April	$1.15	$2.29	$0.88	$112.50	$288.13	$95.00	$250.00
May	$1.18	$2.26	$0.87	$106.60	$279.88	$95.00	$250.00
June	$1.18	$2.20	$0.84	$104.88	$275.63	$95.00	$250.00
July	$1.11	$2.38	$0.92	$108.17	$294.17	$95.00	$250.00
August	$1.10	$2.46	$0.95	$111.90	$313.00	$95.00	$250.00
September	$1.10	$2.40	$0.92	$113.00	$308.13	$96.50	$250.00
October	$1.11	$2.52	$0.97	$115.70	$298.45	$95.00	$250.00
November	$1.06	$2.71	$1.04	$121.38	$304.69	$92.50	$250.00
December	$1.01	$2.79	$1.07	$124.67	$313.33	$92.50	$250.00
January-94	$1.04	$3.02	$1.16	$126.00	$314.38	$97.80	$250.00
February	$1.12	$3.03	$1.16	$127.00	$298.13	$94.50	$250.00
March	$1.11	$2.88	$1.11	$124.40	$289.50	$97.00	$250.00
April	$1.10	$2.72	$1.05	$123.00	$283.75	$98.50	$250.00
May	$1.11	$2.70	$1.04	$121.75	$265.00	$101.00	$250.00
June	$1.14	$2.82	$1.08	$119.34	$262.70	$101.00	$250.00
July	$1.18	$2.40	$0.92	$121.25	$264.38	$97.50	$250.00
August	$1.22	$2.26	$0.87	$119.38	$259.38	$102.50	$250.00
September	$1.22	$2.26	$0.87	$118.90	$240.50	$102.50	$250.00
October	$1.22	$2.16	$0.83	$120.63	$225.00	$102.50	$250.00
November	$1.24	$2.18	$0.84	$118.88	$229.38	$103.50	$250.00
December	$1.25	$2.19	$0.84	$113.13	$237.50	$107.50	$250.00
January-95	$1.22	$2.27	$0.87	$108.50	$236.25	$108.50	$250.00
February	$1.20	$2.32	$0.89	$99.88	$225.63	$108.50	$250.00
March	$1.14	$2.39	$0.92	$95.10	$218.00	$108.50	$250.00
April	$1.11	$2.48	$0.95	$93.25	$210.00	$108.50	$250.00
May	$1.12	$2.56	$0.98	$93.28	$192.50	$108.50	$250.00
June	$1.10	$2.76	$1.06	$95.20	$207.50	$107.30	$250.00
July	$1.07	$2.93	$1.13	$98.13	$211.88	$108.50	$250.00
August	$1.09	$2.86	$1.10	$100.60	$228.50	$106.50	$250.00

Appendix F, con't: Historical Prices for Ethanol Production:

	Ethanol Price $/gallon	Corn Price $/bu	Corn Price $/gallon	DDG ($/ton)	Gluten Meal $/ton	Gluten Feed $/ton	Germ $/ton
September	$1.11	$2.95	$1.13	$106.20	$244.25	$105.50	$250.00
October	$1.13	$3.11	$1.19	$123.25	$270.63	$105.50	$250.00
November	$1.17	$3.37	$1.30	$136.70	$316.80	$105.00	$250.00
December	$1.20	$3.46	$1.33	$140.33	$332.50	$107.50	$250.00
January-96	$1.25	$3.63	$1.39	$139.88	$337.50	$107.50	$250.00
February	$1.26	$3.86	$1.48	$142.60	$343.90	$107.50	$250.00
March	$1.24	$4.03	$1.55	$145.88	$342.38	$107.50	$250.00
April	$1.28	$4.58	$1.76	$152.63	$334.88	$107.50	$250.00
May	$1.37	$4.91	$1.89	$178.70	$342.40	$107.50	$250.00
June	$1.38	$4.84	$1.86	$178.88	$323.13	$107.50	$250.00
July	$1.43	$4.80	$1.84	$161.83	$307.50	$110.00	$250.00
August	$1.53	$4.65	$1.79	$151.20	$298.00	$110.00	$250.00
September	$1.54	$3.81	$1.47	$151.50	$329.38	$108.10	$250.00
October	$1.49	$2.97	$1.14	$140.20	$344.00	$108.10	$250.00
November	$1.38	$2.69	$1.03	$136.25	$340.00	$103.50	$250.00
December	$1.28	$2.69	$1.04	$140.00	$343.13	$97.50	$250.00
January-97	$1.20	$2.67	$1.03	$147.00	$336.25	$94.00	$250.00
February	$1.20	$2.76	$1.06	$147.38	$335.63	$94.00	$250.00
March	$1.19	$2.94	$1.13	$145.13	$341.25	$85.00	$250.00
April	$1.20	$2.94	$1.13	$131.60	$343.13	$85.00	$250.00
May	$1.20	$2.81	$1.08	$121.00	$352.50	$80.00	$250.00
June	$1.14	$2.67	$1.03	$115.00	$349.25	$79.00	$250.00
July	$1.15	$2.55	$0.98	$115.50	$336.25	$81.50	$250.00
August	$1.20	$2.58	$0.99	$120.50	$345.63	$81.50	$250.00
September	$1.22	$2.57	$0.99	$120.75	$356.25	$81.50	$250.00
October	$1.22	$2.62	$1.01	$118.50	$345.50	$80.50	$250.00
November	$1.22	$2.65	$1.02	$120.75	$351.25	$74.25	$250.00
December	$1.22	$2.63	$1.01	$117.75	$352.38	$78.38	$250.00
January-98	$1.19	$2.65	$1.02	$117.50	$321.88	$77.88	$250.00
February	$1.15	$2.65	$1.02	$100.88	$295.00	$76.50	$250.00
March	$1.07	$2.66	$1.02	$92.38	$273.75	$69.75	$250.00
April	$1.03	$2.50	$0.96	$84.40	$241.50	$64.70	$250.00
May	$1.04	$2.47	$0.95	$77.50	$236.25	$64.63	$250.00

Appendix G: Ethanol Producers' Historical Notional Expenses, Credits and Margins

The following are notional net production costs for wet milling ethanol producers and dry milling ethanol producers, based on the prices in Appendix F, and the formulas provided in Appendix E.

	Wet Milling Operation				Dry Milling Operation			
	Expense	**Credit**	**Net**	**Margin**	**Expense**	**Credit**	**Net**	**Margin**
January-92	$1.49	$0.64	$0.84	$0.34	$1.60	$0.51	$1.09	$0.09
February	$1.52	$0.65	$0.87	$0.32	$1.63	$0.52	$1.11	$0.08
March	$1.54	$0.65	$0.89	$0.32	$1.65	$0.51	$1.14	$0.06
April	$1.50	$0.64	$0.86	$0.39	$1.61	$0.49	$1.12	$0.12
May	$1.50	$0.63	$0.87	$0.39	$1.62	$0.48	$1.13	$0.13
June	$1.52	$0.64	$0.89	$0.39	$1.64	$0.48	$1.15	$0.12
July	$1.46	$0.64	$0.82	$0.46	$1.58	$0.50	$1.07	$0.21
August	$1.39	$0.64	$0.76	$0.57	$1.51	$0.51	$0.99	$0.33
September	$1.38	$0.65	$0.73	$0.61	$1.49	$0.52	$0.98	$0.37
October	$1.35	$0.65	$0.70	$0.66	$1.46	$0.52	$0.94	$0.42
November	$1.35	$0.64	$0.71	$0.67	$1.46	$0.52	$0.94	$0.44
December	$1.44	$0.64	$0.80	$0.49	$1.56	$0.53	$1.03	$0.26
January-93	$1.39	$0.65	$0.74	$0.45	$1.51	$0.53	$0.98	$0.21
February	$1.38	$0.63	$0.74	$0.41	$1.49	$0.54	$0.95	$0.20
March	$1.37	$0.64	$0.73	$0.41	$1.49	$0.51	$0.98	$0.16
April	$1.39	$0.63	$0.76	$0.39	$1.51	$0.48	$1.03	$0.12
May	$1.38	$0.63	$0.75	$0.43	$1.50	$0.46	$1.04	$0.14
June	$1.36	$0.63	$0.73	$0.45	$1.47	$0.45	$1.02	$0.16
July	$1.43	$0.64	$0.79	$0.32	$1.54	$0.46	$1.08	$0.03
August	$1.46	$0.65	$0.81	$0.29	$1.57	$0.47	$1.10	($0.00)
September	$1.43	$0.65	$0.78	$0.31	$1.55	$0.48	$1.07	$0.03
October	$1.48	$0.64	$0.84	$0.27	$1.59	$0.49	$1.11	($0.00)
November	$1.55	$0.64	$0.92	$0.14	$1.67	$0.50	$1.16	($0.10)
December	$1.58	$0.64	$0.94	$0.07	$1.70	$0.52	$1.18	($0.18)
January-94	$1.67	$0.65	$1.02	$0.02	$1.78	$0.52	$1.26	($0.22)
February	$1.68	$0.64	$1.04	$0.08	$1.79	$0.52	$1.27	($0.15)
March	$1.62	$0.64	$0.98	$0.13	$1.73	$0.52	$1.22	($0.11)
April	$1.56	$0.64	$0.92	$0.18	$1.67	$0.51	$1.16	($0.06)
May	$1.55	$0.63	$0.92	$0.19	$1.66	$0.51	$1.16	($0.05)
June	$1.60	$0.63	$0.96	$0.17	$1.71	$0.50	$1.21	($0.07)
July	$1.44	$0.63	$0.81	$0.37	$1.55	$0.50	$1.05	$0.13
August	$1.38	$0.63	$0.75	$0.48	$1.49	$0.50	$1.00	$0.23
September	$1.38	$0.62	$0.76	$0.46	$1.50	$0.50	$1.00	$0.22
October	$1.34	$0.61	$0.73	$0.49	$1.45	$0.50	$0.95	$0.27
November	$1.35	$0.62	$0.73	$0.51	$1.46	$0.50	$0.97	$0.27
December	$1.35	$0.63	$0.72	$0.53	$1.47	$0.48	$0.99	$0.26
January-95	$1.38	$0.63	$0.75	$0.47	$1.50	$0.46	$1.03	$0.19
February	$1.40	$0.63	$0.78	$0.42	$1.52	$0.43	$1.08	$0.11
March	$1.43	$0.62	$0.81	$0.33	$1.54	$0.42	$1.13	$0.01
April	$1.46	$0.62	$0.85	$0.27	$1.58	$0.41	$1.17	($0.05)
May	$1.50	$0.61	$0.89	$0.23	$1.61	$0.41	$1.20	($0.08)
June	$1.57	$0.61	$0.96	$0.14	$1.69	$0.42	$1.27	($0.17)
July	$1.64	$0.62	$1.02	$0.05	$1.75	$0.43	$1.32	($0.25)
August	$1.61	$0.62	$0.99	$0.10	$1.73	$0.44	$1.29	($0.20)
September	$1.64	$0.63	$1.01	$0.09	$1.76	$0.45	$1.30	($0.20)

Appendix G, con't: Ethanol Producers' Historical Notional Expenses, Credits and Margins

	Wet Milling Operation				Dry Milling Operation			
	Expense	**Credit**	**Net**	**Margin**	**Expense**	**Credit**	**Net**	**Margin**
October	$1.71	$0.65	$1.06	$0.07	$1.82	$0.51	$1.31	($0.17)
November	$1.81	$0.67	$1.14	$0.03	$1.92	$0.56	$1.37	($0.20)
December	$1.84	$0.68	$1.16	$0.04	$1.96	$0.57	$1.39	($0.19)
January-96	$1.91	$0.69	$1.22	$0.03	$2.02	$0.57	$1.45	($0.20)
February	$1.99	$0.69	$1.31	-$0.05	$2.11	$0.58	$1.53	($0.28)
March	$2.06	$0.69	$1.37	-$0.13	$2.17	$0.59	$1.59	($0.35)
April	$2.27	$0.68	$1.59	-$0.30	$2.38	$0.61	$1.78	($0.49)
May	$2.40	$0.69	$1.71	-$0.34	$2.51	$0.70	$1.82	($0.45)
June	$2.37	$0.68	$1.70	-$0.31	$2.49	$0.70	$1.79	($0.41)
July	$2.36	$0.67	$1.68	-$0.26	$2.47	$0.64	$1.83	($0.40)
August	$2.30	$0.67	$1.63	-$0.10	$2.41	$0.60	$1.81	($0.28)
September	$1.98	$0.68	$1.30	$0.24	$2.09	$0.61	$1.49	$0.05
October	$1.65	$0.69	$0.96	$0.53	$1.77	$0.57	$1.20	$0.29
November	$1.55	$0.68	$0.87	$0.51	$1.66	$0.55	$1.10	$0.27
December	$1.55	$0.67	$0.88	$0.40	$1.66	$0.57	$1.09	$0.19
January-97	$1.54	$0.66	$0.88	$0.32	$1.65	$0.59	$1.06	$0.13
February	$1.57	$0.66	$0.91	$0.28	$1.69	$0.59	$1.09	$0.10
March	$1.64	$0.64	$1.00	$0.20	$1.76	$0.58	$1.17	$0.02
April	$1.64	$0.65	$1.00	$0.20	$1.76	$0.54	$1.22	($0.02)
May	$1.59	$0.64	$0.95	$0.25	$1.71	$0.50	$1.20	($0.01)
June	$1.54	$0.64	$0.90	$0.24	$1.65	$0.48	$1.17	($0.03)
July	$1.49	$0.64	$0.86	$0.30	$1.61	$0.49	$1.12	$0.03
August	$1.50	$0.64	$0.86	$0.34	$1.62	$0.50	$1.11	$0.09
September	$1.50	$0.65	$0.85	$0.37	$1.61	$0.50	$1.11	$0.11
October	$1.52	$0.64	$0.88	$0.34	$1.63	$0.50	$1.14	$0.09
November	$1.53	$0.63	$0.90	$0.32	$1.64	$0.50	$1.14	$0.08
December	$1.52	$0.64	$0.89	$0.34	$1.64	$0.49	$1.14	$0.08
January-98	$1.53	$0.62	$0.91	$0.28	$1.64	$0.49	$1.15	$0.04
February	$1.53	$0.60	$0.93	$0.22	$1.64	$0.44	$1.21	($0.06)
March	$1.54	$0.58	$0.96	$0.12	$1.65	$0.41	$1.24	($0.17)
April	$1.47	$0.55	$0.92	$0.11	$1.59	$0.38	$1.20	($0.17)
May	$1.46	$0.55	$0.91	$0.12	$1.57	$0.36	$1.21	($0.18)

Average wet milling production cost: $.95/gallon
Average dry milling production cost: $1.19/gallon

Weighted ethanol producers notional net production cost (67% wet milling, 33% dry milling): $1.03/gallon

Appendix H: Corn production and cost by state

The following data is based on U.S. Department of Agriculture data. For the purposes of this study, a base of $2.60 per bushel was used as the notional weighted average U.S. price for corn ($2.60/bu is close to the average price provided by Hart Publishing in Appendix F, excluding the period of Oct 1995 -Sept 1996 when corn prices were very high). The state by state corn prices below were calculated by taking the actual (USDA) average state prices from 1988-1996, determining a differential to the weighted average US USDA price, and subtracting or adding those differentials to the base of $2.60/bushel. Production data is actual from 1996.

	Corn $/bu	Production ('000 bu)
SD	$ 2.37	370,000
MN	$ 2.44	868,750
ND	$ 2.44	65,520
MI	$ 2.51	216,200
IA	$ 2.54	1,718,100
WI	$ 2.54	333,000
NE	$ 2.59	1,186,900
OH	$ 2.62	305,250
IN	$ 2.63	670,350
IL	$ 2.65	1,468,800
KS	$ 2.66	357,200
MO	$ 2.69	355,100
CO	$ 2.70	133,480
AR	$ 2.73	28,750
TN	$ 2.74	78,880
KY	$ 2.75	148,800
MS	$ 2.80	61,710
MT	$ 2.80	2,055
LA	$ 2.84	65,375
WY	$ 2.85	6,150
TX	$ 2.85	201,600
MD	$ 2.85	64,635
NJ	$ 2.85	11,844
VA	$ 2.86	39,060
DE	$ 2.87	21,450
NM	$ 2.87	14,700
WV	$ 2.89	4,200
OK	$ 2.89	24,650
NC	$ 2.90	85,500
FL	$ 2.90	9,856
SC	$ 2.91	30,020
AL	$ 2.95	22,960
NY	$ 2.97	67,410
PA	$ 2.97	127,330
GA	$ 2.98	49,875
WA	$ 3.13	22,200
OR	$ 3.19	5,445
ID	$ 3.23	5,400
UT	$ 3.28	2,730
AZ	$ 3.33	7,000
CA	$ 3.34	35,200
Ontario	$ 3.22	

Appendix I: Notional Ethanol Production Costs, by state

The following table estimates the notional net cost of ethanol production in each state, based solely on differing corn costs. All other costs and byproduct credits are held constant. States are listed twice; the first listing refers to the net production cost of wet milling ethanol production, the second refers to net production costs of dry milling ethanol production. Existing production capacity for each state are listed.

State	Net ethanol Cost ($/g)	Wet milling capacity	Dry milling capacity	State	Net ethanol cost ($/g)	Wet milling Capacity	Dry Milling Capacity
SD	$0.79	-	-	IA	$1.11		2,348
MN	$0.82	2,609	-	WI	$1.11		163
ND	$0.82	-	-	ONTARIO	$1.12		2,585
MI	$0.84	-	-	ID	$1.12		-
IA	$0.85	25,440	-	NE	$1.13		7,502
WI	$0.85	-	-	UT	$1.14		1,305
NE	$0.88	10,111	-	OH	$1.14		-
OH	$0.88	-	-	IN	$1.15		-
IN	$0.89	5,545	-	IL	$1.15		815
IL	$0.90	33,268	-	KS	$1.16		3,725
KS	$0.90	-	-	AZ	$1.16		-
MO	$0.91	-	-	CA	$1.16		-
CO	$0.92	-	-	MO	$1.17		-
AR	$0.93	-	-	CO	$1.17		98
TN	$0.93	2,740	-	AR	$1.18		-
KY	$0.94	-	-	TN	$1.19		-
MS	$0.95	-	-	KY	$1.19		652
MT	$0.96	-	-	MS	$1.21		-
LA	$0.97	-	-	MT	$1.21		-
WY	$0.97	-	-	LA	$1.22		-
TX	$0.97	-	-	WY	$1.23		326
MD	$0.97	-	-	TX	$1.23		1,376
NJ	$0.97	-	-	MD	$1.23		-
VA	$0.98	-	-	NJ	$1.23		-
DE	$0.98	-	-	VA	$1.23		-
NM	$0.98	-	-	DE	$1.24		-
WV	$0.99	-	-	NM	$1.24		1,957
OK	$0.99	-	-	WV	$1.25		-
NC	$0.99	-	-	OK	$1.25		-
FL	$0.99	-	-	NC	$1.25		-
SC	$1.00	-	-	FL	$1.25		-
AL	$1.01	-	-	SC	$1.25		1,285
NY	$1.02	-	-	AL	$1.27		-
PA	$1.02	-	-	NY	$1.27		-
GA	$1.02	-	-	PA	$1.28		-
SD	$1.04	-	995	GA	$1.28		-
MN	$1.07	-	5,166	WA	$1.34		-
ND	$1.07	-	652	OR	$1.36		-
WA	$1.08	-		ID	$1.38		-
MI	$1.10	-		UT	$1.39		-
OR	$1.11	-		AZ	$1.42		-
				CA	$1.42		-

Appendix J: Calculation of long term byproduct elasticities and long term cost of ethanol

In determining the long term net production cost of ethanol, increased ethanol demand is assumed to increase the price of corn while decreasing the received price for ethanol production by-products, such as distillers' dried grains (DDG), corn gluten meal, corn gluten feed, and corn germ. Long term elasticities of supply are used to determine the effect on the long term prices of corn and corn byproducts. The long term elasticity value, "e", is defined as the change in price divided by the change in supply.

The long term elasticity of corn was supplied by the U.S. Department of Agriculture as 0.3. For the by-products, secondary source data was used to estimate elasticities. A USDA report from 1993 estimated the change in price of byproducts caused by an increase in ethanol demand (and thus an increase in corn processing). This report estimated that a change in ethanol production from 1.2 billion gallons to 5 billion gallons (a change of 3.8 billion gallons) over 7 years would cause the price of corn gluten meal to fall 7 percent, corn gluten feed to fall 12.3 percent, and distillers' dried grains to fall 4 percent. No estimation was provided for germ; an average of the price decline of corn gluten meal and corn gluten feed was assumed as a proxy (a decline of 7.7 percent). Wet milling production (which supplies byproducts of corn germ, corn gluten meal and corn gluten feed) was assumed to remain at 67 percent of national ethanol production, while dry milling production (which supplies byproduct of DDG) was assumed to remain at 33 percent of national ethanol production. Thus the base ethanol demand (1.2 billion gallons) and increase in ethanol demand (3.8 billion gallons) are multiplied by .33 for determining the change in DDG supply and .67 for determining the change in all other byproduct supplies. The elasticity calculations are provided below:

DDG (17.35 lbs per bushel at 10% moisture)

	Change in ethanol demand	In bushels of corn	In tons of DDG
Change	1,254,000,000	482,307,692	4,184,019
Base	396,000,000	152,307,692	1,321,269
% Change in Supply			317%
Change in Price			4%
Elasticity (e = ? P / ? S)			0.0126

Gluten meal (2.88 lbs per bushel at 10% moisture)

	Change in ethanol demand	In bushels of corn	In tons of gluten meal
Change	2,546,000,000	979,230,769	1,410,092
Base	804,000,000	309,230,769	445,292
% Change in Supply			317%
Change in Price			7%
Elasticity (e = ? P / ? S)			0.0221

Gluten feed (10 lbs per bushel at 12% moisture)

	Change in ethanol demand	In bushels of corn	In tons of gluten feed
Change	2,546,000,000	979,230,769	4,896,154
Base	804,000,000	309,230,769	1,546,154
% Change in Supply			317%
Change in Price			12.3%
Elasticity (e = ? P / ? S)			0.0388

Appendix J, con't: Calculation of long term byproduct elasticities and long term cost of ethanol

Germ (4 lbs per bushel at 2% moisture)

	Change in ethanol demand	In bushels of corn	In tons of germ
Change	2,546,000,000	979,230,769	1,958,462
Base	804,000,000	309,230,769	618,462
% Change in Supply			317%
Change in Price			7.7%
Elasticity (e = ? P / ? S)			0.0243

In order to determine the long term cost of ethanol, the elasticities as calculated above are applied to changes in ethanol demand. The resulting net production costs for wet millers and dry millers are calculated below. The assumptions are a base U.S. corn production level of 10.1 billion bushels, a base corn price of $2.60/bushel, and base byproduct prices of : $118.5 per ton for DDGs, $283.7 per ton for corn gluten meal, $97.4 per ton for corn gluten feed, and $250 per ton for corn germ. These base price assumptions were taken from the average historical prices provided above in Appendix F, excluding the period of Oct. 1995-Sept. 1996 during which corn prices were abnormally high. Three ethanol demand levels are listed below: 10,000 b/d, 50,000 b/d and 100,000 b/d.

Total new ethanol demand (b/d):	**10,000**	**50,000**	**100,000**
In gallons/year:	153,300,000	766,500,000	1,533,000,000
Additional bushels required:	58,961,538	294,807,692	589,615,385
Elasticity effect on price			
(? P = e * ? S):	0.18%	0.88%	1.75%
Price of corn:	$2.605	$2.623	$2.646
in $/gallon of ethanol	$1.002	$1.009	$1.018
Negative change in DDG price			
(? P = e * ? S)	0.16%	0.81%	1.61%
Price of DDG	$118.31	$117.54	$116.58
in $/gallon of ethanol	$0.395	$0.392	$0.389
Negative change in gluten meal price			
(? P = e * ? S)	0.28%	1.41%	2.82%
gluten meal price	$282.90	$279.69	$275.69
in $/gallon of ethanol	$0.157	$0.155	$0.153
Negative change in gluten feed price			
(? P = e * ? S)	0.50%	2.48%	4.96%
gluten feed price	$96.91	$94.98	$92.56
in $/gallon of ethanol	$0.186	$0.183	$0.178
Negative change in germ price			
(? P = e * ? S)	0.31%	1.55%	3.11%
germ price	$249.22	$246.12	$242.23
in $/gallon of ethanol	$0.192	$0.189	$0.186

Appendix J, con't: Calculation of long term byproduct elasticities and long term cost of ethanol

Expenses (WET MILL)	$1.51	$1.52	$1.53
Credits (WET MILL)	$0.53	$0.53	$0.52
Net production cost (WET MILL)	$0.98	$0.99	$1.01
Expenses (DRY MILL)	$1.63	$1.63	$1.64
Credits (DRY MILL)	$0.39	$0.39	$0.39
Net production cost (DRY MILL)	$1.23	$1.24	$1.25
Weighted average (67% wet mill, 33% dry mill)	$1.06	$1.08	$1.09
Ethanol price minus subsidy of $.54/gallon	$0.52	$0.54	$0.55

Appendix K: Energy price assumptions

Los Angeles	
Butane	28.61
Isobutane	52.82
Propane	34.22
Conv. Unleaded	60.73
CARB Unleaded	63.72
Conv. Premium	67.71
CARB Premium	67.98
Jet	57.41
Low Sulfur Diesel	54.70
CARB Diesel	60.93
HSFO 3% $/bbl	14.59
USGC	
Unleaded	59.66
RFG Unleaded	62.22
Midgrade	61.46
RFG Midgrade	64.06
Premium	64.96
Pool gasoline	62.03
RFG Premium	67.50
Jet	54.02
High S Diesel	51.69
Low Sulfur Diesel	52.41
No. 6, 3% S, $/Bbl	14.45
MTBE	85.39
Methanol	61.22
Octane	1.06
RVP	- 0.61

International and other U.S. prices (the following prices were determined by calculating a differential based on Gulf Coast prices from the ESAI price database, and then applying that differential to the appropriate price as listed above).

Europe MTBE	81.9	
New York Harbor MTBE	89.4	
Mediterranean pool mogas		57.0
Northwest Europe pool mogas	56.5	
Singapore pool mogas	62.1	
New York Harbor mogas	63.5	

Additional price assumptions:

C4 alkylate (94 octane, 7.5 RVP) 72.0

Derived as follows (derivation provided by Valero Energy Corp):
C4 alkylate = 87 octane mogas + octane value * (94-87) - RVP value * (7.5 - 7.5)

Butylene as alkylation feedstock: 69.9
Derived as follows (derivation provided by Valero Energy Corp):
1.0 butylene = 1.92 alkylate - 1.205 isobutane - 0.115 N-butane - 1.3 cents/gallon

Appendix L: Transportation cost assumptions

	Cents/gallon	Ethanol (water soluble surcharge)	
Gulf Coast to California		8	9
Midwest to California	15		
Southeast Asia to California	7	8	
Northeast Asia to California	6.5	7.5	
Brazil to Gulf Coast	5.5	6.5	
Brazil to California	9.29	10.29	
Venezuela to Gulf Coast		2.4	3.4
Venezuela to California	5.68	6.68	
Middle East to California	9.76	10.76	
Canada to California	3	4	
NW Europe to Atlantic Coast	3.29	4.29	
Med Europe to Atlantic Coast	4.14	5.14	
NW Europe to California	8.2	9.2	
Med Europe to California	8.9	9.9	
Caribbean to California	5.7	6.7	

Appendix M: Alternate Oxygenate Supply Curves

Table M-1

MTBE delivered to California
Intermediate Term
Base Case

Incremental Volume	Total Volume	Price	Delivered price to California
16,000	16,000	73.3	76.3
25,000	41,000	73.3	83.0
13,000	54,000	86.5	86.5
3,000	57,000	83.0	90.0
7,000	64,000	87.7	93.4
45,000	109,000	86.5	94.5

Table M-2

MTBE delivered to California
Intermediate Term
Base Case

Incremental Volume	Total Volume	Price	Delivered price to California
31,000	31,000	73.0	76.0
40,000	71,000	73.0	82.8
20,000	91,000	73.0	82.8
15,000	106,000	86.5	86.5
27,000	133,000	87.7	93.4

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-3

Ethanol delivered to California
Intermediate Term
Tax credit for ethanol
California ban of MTBE

Incremental Volume	Total Volume	Price	Delivered price to California	Including subsidy of 54 cents/gallon
60	60	64.4	79.4	133.4
126	187	65.1	80.1	134.1
474	661	65.3	80.3	134.3
72	732	65.6	80.6	134.6
2,105	2,837	65.6	80.6	134.6
4,419	7,256	65.6	80.6	134.6
173	7,429	65.7	80.7	134.7
1,302	8,731	66.0	81.0	135.0
1,021	9,752	66.4	81.4	135.4
3,410	13,162	67.1	82.1	136.1
1,492	14,655	67.2	82.2	136.2
385	15,040	67.2	82.2	136.2
1,546	16,586	67.2	82.2	136.2
304	16,890	68.1	83.1	137.1
144	17,034	68.2	83.2	137.2
5,391	22,425	68.2	83.2	137.2
312	22,737	68.7	83.7	137.7
4,277	27,013	69.2	84.2	138.2
2,925	29,938	69.6	84.6	138.6
821	30,760	71.9	86.9	140.9
7,700	38,460	60.0	82.7	136.7
12,883	51,342	76.1	91.1	145.1
10,392	61,734	80.3	95.3	149.3
1,175	62,909	87.9	102.9	156.9
1,243	64,153	89.1	104.1	158.1
30,000	94,153	88.7	103.7	157.7
1,453	95,606	90.7	105.7	159.7
827	96,433	91.0	106.0	160.0
42	96,475	91.7	106.7	160.7
1,939	98,414	91.8	106.8	160.8

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-4

Ethanol delivered to California
Long Term
Tax credit for ethanol
California ban of MTBE

Incremental Volume	Total Volume	Price	Price to California	Including subsidy of 54 cent/gallon
10,000	10,000	52.2	67.2	121.2
10,000	20,000	52.5	67.5	121.5
10,000	30,000	52.9	67.9	121.9
10,000	40,000	53.2	68.2	122.2
10,000	50,000	53.5	68.5	122.5
10,000	60,000	53.8	68.8	122.8
10,000	70,000	54.2	69.2	123.2
10,000	80,000	54.5	69.5	123.5
10,000	90,000	54.8	69.8	123.8
10,000	100,000	55.2	70.2	124.2
10,000	110,000	55.5	70.5	124.5
10,000	120,000	55.8	70.8	124.8

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-5

Ethanol delivered to California
Intermediate Term
No tax credit for ethanol
California ban of MTBE

Incremental Volume	Total Volume	Price	Price to California
7,700	7,700	60.0	82.7
13,050	20,750	85.3	100.3
10,111	30,860	87.6	102.6
5,545	36,405	89.0	104.0
33,268	69,673	89.7	104.7
2,740	72,413	93.1	108.1
995	73,408	104.3	119.3
5,166	78,574	107.3	122.3
652	79,226	107.3	122.3
2,348	81,575	110.8	125.8
163	81,738	110.8	125.8
2,585	84,323	112.0	127.0
7,502	91,824	113.1	128.1
1,305	93,129	113.9	128.9
815	93,944	115.2	130.2
3,725	97,669	115.6	130.6
98	97,767	117.2	132.2
652	98,419	119.1	134.1
326	98,745	122.8	137.8
1,376	100,122	122.9	137.9
1,957	102,079	123.7	138.7

Table M-6

Ethanol delivered to California
Long Term
No tax credit for ethanol
California ban of MTBE

Incremental volume	Total Volume	Price	Price to California
7,700	7,700	60.0	82.7
8,423	16,123	78.8	93.8
11,032	27,155	81.8	96.8
25,440	52,595	85.3	100.3
18,534	71,128	87.6	102.6
5,545	76,673	89.0	104.0
33,268	109,941	89.7	104.7

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-7

ETBE delivered to California
Intermediate Term
Tax credit for ethanol
California ban of MTBE

Incremental Volume	Total volume of ETBE	Volume of ethanol feedstock	Ethanol input	ETBE Cost	Price to California	Minus Subsidy
5,000	5,000	2,150	134.6	111.1	114.1	90.9
5,000	10,000	4,300	134.6	111.1	114.1	90.9
5,000	15,000	6,450	134.6	111.1	114.1	90.9
5,000	20,000	8,600	135.0	111.2	114.2	91.0
5,000	25,000	10,750	129.1	108.7	117.7	94.5
5,000	30,000	12,900	129.1	108.7	117.7	94.5
5,000	35,000	15,050	129.2	108.8	117.8	94.6
5,000	40,000	17,200	130.2	109.2	118.2	95.0
5,000	45,000	19,350	130.2	109.2	118.2	95.0
5,000	50,000	21,500	130.2	109.2	118.2	95.0
5,000	55,000	23,650	131.2	109.6	118.6	95.4
5,000	60,000	25,800	131.2	109.6	118.6	95.4
5,000	65,000	27,950	131.6	109.8	118.8	95.6
5,000	70,000	30,100	133.9	110.8	119.8	96.6
5,000	75,000	32,250	136.0	111.7	120.7	97.5
5,000	80,000	34,400	136.0	111.7	120.7	97.5
5,000	85,000	36,550	136.0	111.7	120.7	97.5
5,000	90,000	38,700	138.1	112.6	121.6	98.4
5,000	95,000	40,850	138.1	112.6	121.6	98.4
5,000	100,000	43,000	138.1	112.6	121.6	98.4
5,000	105,000	45,150	138.1	112.6	121.6	98.4
5,000	110,000	47,300	150.7	118.0	127.0	103.8
5,000	115,000	49,450	150.9	118.1	127.1	103.9
5,000	120,000	51,600	152.4	118.7	127.7	104.5
5,000	125,000	53,750	152.4	118.7	127.7	104.5
5,000	130,000	55,900	156.5	120.5	129.5	106.3
5,000	135,000	58,050	156.5	120.5	129.5	106.3
5,000	140,000	60,200	156.5	120.5	129.5	106.3
5,000	145,000	62,350	156.5	120.5	129.5	106.3
5,000	150,000	64,500	156.5	120.5	129.5	106.3
5,000	155,000	66,650	156.5	120.5	129.5	106.3
5,000	160,000	68,800	156.5	120.5	129.5	106.3
5,000	165,000	70,950	159.6	121.8	130.8	107.6
5,000	170,000	73,100	159.7	121.9	130.9	107.7
5,000	175,000	75,250	159.7	121.9	130.9	107.7
5,000	180,000	77,400	159.9	122.0	131.0	107.8

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-8

ETBE delivered to California
Long Term
Tax credit for ethanol
California ban of MTBE

Incremental Volume of ETBE	Total Volume of ETBE	Ethanol Feedstock	Ethanol Input Price	ETBE Price	Delivered Price to California	Less Tax credit
5,000	5,000	2,150	121.2	105.3	108.3	85.1
5,000	10,000	4,300	121.2	105.3	105.3	82.1
5,000	15,000	6,450	121.2	105.3	108.3	85.1
5,000	20,000	8,600	121.2	105.3	108.3	85.1
5,000	25,000	10,750	121.5	105.5	108.5	85.3
5,000	30,000	12,900	121.5	105.5	108.5	85.3
5,000	35,000	15,050	121.5	105.5	108.5	85.3
5,000	40,000	17,200	114.5	102.4	111.4	88.2
5,000	45,000	19,350	114.5	102.4	111.4	88.2
5,000	50,000	21,500	114.9	102.6	111.6	88.4
5,000	55,000	23,650	114.9	102.6	111.6	88.4
5,000	60,000	25,800	114.9	102.6	111.6	88.4
5,000	65,000	27,950	114.9	102.6	111.6	88.4
5,000	70,000	30,100	114.9	102.6	111.6	88.4
5,000	75,000	32,250	114.9	102.6	111.6	88.4
5,000	80,000	34,400	114.9	102.6	111.6	88.4
5,000	85,000	36,550	114.9	102.6	111.6	88.4
5,000	90,000	38,700	114.9	102.6	111.6	88.4
5,000	95,000	40,850	115.2	102.7	111.7	88.5
5,000	100,000	43,000	115.2	102.7	111.7	88.5
5,000	105,000	45,150	115.2	102.7	111.7	88.5
5,000	110,000	47,300	115.2	102.7	111.7	88.5
5,000	115,000	49,450	115.2	102.7	111.7	88.5
5,000	120,000	51,600	115.8	103.0	112.0	88.8
5,000	125,000	53,750	115.8	103.0	112.0	88.8
5,000	130,000	55,900	115.8	103.0	112.0	88.8
5,000	135,000	58,050	115.8	103.0	112.0	88.8
5,000	140,000	60,200	116.2	103.1	112.1	88.9
5,000	145,000	62,350	116.2	103.1	112.1	88.9
5,000	150,000	64,500	116.2	103.1	112.1	88.9
5,000	155,000	66,650	116.2	103.1	112.1	88.9
5,000	160,000	68,800	116.2	103.1	112.1	88.9
5,000	165,000	70,950	116.5	103.3	112.3	89.1
5,000	170,000	73,100	116.5	103.3	112.3	89.1
5,000	175,000	75,250	116.5	103.3	112.3	89.1
5,000	180,000	77,400	116.5	103.3	112.3	89.1

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-9

ETBE delivered to California
Intermediate Term
No tax credit for ethanol
California ban of MTBE

Incremental Volume of ETBE	Total Volume of ETBE	Ethanol Feedstock	Ethanol Input Price	ETBE Price	Delivered Price to California
5,000	2,150	5,000	82.7	88.8	91.8
5,000	4,300	10,000	82.7	88.8	91.8
5,000	6,450	15,000	82.7	88.8	91.8
5,000	8,600	20,000	93.3	93.3	102.3
5,000	10,750	25,000	93.3	93.3	102.3
5,000	12,900	30,000	93.3	93.3	102.3
5,000	15,050	35,000	93.3	93.3	102.3
5,000	17,200	40,000	93.3	93.3	102.3
5,000	19,350	45,000	93.3	93.3	102.3
5,000	21,500	50,000	95.6	94.3	103.3
5,000	23,650	55,000	95.6	94.3	103.3
5,000	25,800	60,000	95.6	94.3	103.3
5,000	27,950	65,000	95.6	94.3	103.3
5,000	30,100	70,000	95.6	94.3	103.3
5,000	32,250	75,000	97.0	94.9	103.9
5,000	34,400	80,000	97.0	94.9	103.9
5,000	36,550	85,000	97.7	95.2	104.2
5,000	38,700	90,000	97.7	95.2	104.2
5,000	40,850	95,000	97.7	95.2	104.2
5,000	43,000	100,000	97.7	95.2	104.2
5,000	45,150	105,000	97.7	95.2	104.2
5,000	47,300	110,000	97.7	95.2	104.2
5,000	49,450	115,000	97.7	95.2	104.2
5,000	51,600	120,000	97.7	95.2	104.2
5,000	53,750	125,000	97.7	95.2	104.2
5,000	55,900	130,000	97.7	95.2	104.2
5,000	58,050	135,000	97.7	95.2	104.2
5,000	60,200	140,000	97.7	95.2	104.2
5,000	62,350	145,000	97.7	95.2	104.2
5,000	64,500	150,000	97.7	95.2	104.2
5,000	66,650	155,000	97.7	95.2	104.2
5,000	68,800	160,000	97.7	95.2	104.2
5,000	70,950	165,000	101.1	96.6	105.6
5,000	73,100	170,000	112.3	101.5	110.5

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-10

ETBE delivered to California
Long Term
No tax credit for ethanol
California ban of MTBE

Incremental Volume of ETBE	Total Volume of ETBE	Ethanol Feedstock	Ethanol Input Price	ETBE Price	Delivered Price to California
10,000	10,000	4,300	82.7	88.8	91.8
10,000	20,000	8,600	93.8	93.5	96.5
10,000	30,000	12,900	93.8	93.5	96.5
10,000	40,000	17,200	89.8	91.8	100.8
10,000	50,000	21,500	89.8	91.8	100.8
10,000	60,000	25,800	89.8	91.8	100.8
10,000	70,000	30,100	93.3	93.3	102.3
10,000	80,000	34,400	93.3	93.3	102.3
10,000	90,000	38,700	93.3	93.3	102.3
10,000	100,000	43,000	93.3	93.3	102.3
10,000	110,000	47,300	93.3	93.3	102.3
10,000	120,000	51,600	93.3	93.3	102.3
10,000	130,000	55,900	95.6	94.3	103.3
10,000	140,000	60,200	95.6	94.3	103.3
10,000	150,000	64,500	95.6	94.3	103.3
10,000	160,000	68,800	95.6	94.3	103.3
10,000	170,000	73,100	97.0	94.9	103.9

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-11

TAME delivered to California
Intermediate Term
California ban of MTBE

Incremental Volume of TAME	Total Volume of TAME	Price	Price to California
5,100	5,100	85.3	95.3
2,300	7,400	77.2	95.4
4,784	12,184	77.3	96.2
9,350	21,534	80.9	96.6
15,610	37,144	80.9	98.9
1,500	38,644	84.5	101.5
2,572	41,216	84.6	104.6
5,603	46,819	84.7	104.7

Table M-12

TBA delivered to California
Intermediate Term
California ban of MTBE

Incremental Volume	Total Volume	Price	Delivered price to California
14,400	14,400	80.6	83.6
54,600	69,000	84.1	92.1
10,400	79,400	76.4	94.6
10,800	90,200	76.4	95.3
34,800	125,000	80.7	98.7

Table M-13

TBA delivered to California
Long Term
California ban of MTBE

Incremental Volume	Total Volume	Price	Delivered price to California
24,800	24,800	75.1	78.1
32,000	56,800	75.1	84.8
16,000	72,800	75.1	84.8
12,000	84,800	87.4	87.4
34,800	119,600	80.7	88.7

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-14

Ethanol delivered to California
Intermediate Term
Tax credit for ethanol
U.S. ban of MTBE

Incremental Volume	Total Volume	Price w/	Delivered price to California	subsidy
592	592	86.4	101.4	155.4
184	776	86.8	101.8	155.8
1,258	2,034	88.1	103.1	157.1
45	2,079	88.2	103.2	157.2
1,703	3,782	91.0	106.0	160.0
6,159	9,941	92.0	107.0	161.0
2,799	12,740	92.2	107.2	161.2
2,576	15,316	93.6	108.6	162.6
16,711	32,027	95.2	110.2	164.2
1,279	33,306	98.3	113.3	167.3
5,069	38,375	98.5	113.5	167.5
2,034	40,410	98.6	113.6	167.6
9,727	50,137	98.9	113.9	167.9
15,108	65,245	98.9	113.9	167.9
1,828	67,073	99.2	114.2	168.2
10,961	78,034	100.2	115.2	169.2
1,406	79,441	100.8	115.8	169.8
9,676	89,117	101.1	116.1	170.1
6,755	95,872	101.4	116.4	170.4
2,502	98,374	101.5	116.5	170.5
1,771	100,145	101.7	116.7	170.7
5,081	105,226	101.8	116.8	170.8
1,431	106,657	102.5	117.5	171.5
7,387	114,044	102.6	117.6	171.6

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-15

Ethanol delivered to California
Long Term
Tax credit for ethanol
U.S. ban of MTBE

Incremental Volume	Total Volume	Price	Price to California	Price with 54 c/g subsidy
5,000	5,000	55.5	70.5	124.5
5,000	10,000	55.8	70.8	124.8
5,000	15,000	56.1	71.1	125.1
5,000	20,000	56.5	71.5	125.5
5,000	25,000	56.8	71.8	125.8
5,000	30,000	57.1	72.1	126.1
5,000	35,000	57.5	72.5	126.5
5,000	40,000	57.8	72.8	126.8
5,000	45,000	58.1	73.1	127.1
5,000	50,000	58.4	73.4	127.4
5,000	55,000	58.8	73.8	127.8
5,000	60,000	59.1	74.1	128.1
5,000	65,000	59.4	74.4	128.4
5,000	70,000	59.8	74.8	128.8
5,000	75,000	60.1	75.1	129.1
5,000	80,000	60.4	75.4	129.4
5,000	85,000	60.7	75.7	129.7
5,000	90,000	61.1	76.1	130.1
5,000	95,000	61.4	76.4	130.4
5,000	100,000	61.7	76.7	130.7

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-16
Ethanol delivered to California
Intermediate Term
No tax credit for ethanol
U.S. ban of MTBE

Total Volume	Incremental volume	Price	Delivered price to California
7,700	7,700	60.0	82.7
20,750	13,050	85.3	100.3
30,860	10,111	87.6	102.6
36,405	5,545	89.0	104.0
69,673	33,268	89.7	104.7
72,413	2,740	93.1	108.1
73,408	995	104.3	119.3
78,574	5,166	107.3	122.3
79,226	652	107.3	122.3
81,575	2,348	110.8	125.8
81,738	163	110.8	125.8
84,323	2,585	112.0	127.0
91,824	7,502	113.1	128.1
93,129	1,305	113.9	128.9
93,944	815	115.2	130.2
97,669	3,725	115.6	130.6
97,767	98	117.2	132.2
98,419	652	119.1	134.1
98,745	326	122.8	137.8
100,122	1,376	122.9	137.9
102,079	1,957	123.7	138.7
105,026	2,948	133.8	148.8
107,928	2,902	137.7	152.7
110,700	2,771	141.8	156.8

Table M-17
Ethanol delivered to California
Long Term
No tax credit for ethanol
U.S. ban of MTBE

Incremental volume	Total volume	Price	Delivered price to California
7,700	7,700	60.0	82.7
8,423	16,123	78.8	93.8
11,032	27,155	81.8	96.8
25,440	52,595	85.3	100.3
18,534	71,128	87.6	102.6
5,545	76,673	89.0	104.0
33,268	109,941	89.7	104.7

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-18

ETBE delivered to California
Intermediate Term
Tax credit for ethanol
U.S. ban of MTBE

Incremental Volume of ETBE	Total volume of ETBE	Ethanol feedstock volume	Ethanol cost	ETBE price	ETBE delivered price to California	Less subsidy
5,000	5,000	2,150	160.0	122.2	122.2	99.0
5,000	10,000	4,300	161.0	122.6	122.6	99.4
5,000	15,000	6,450	161.0	122.6	125.6	102.4
5,000	20,000	8,600	161.0	122.6	125.6	102.4
5,000	25,000	10,750	161.2	122.7	125.7	102.5
5,000	30,000	12,900	161.2	122.7	125.7	102.5
5,000	35,000	15,050	155.6	120.2	129.2	106.0
5,000	40,000	17,200	157.2	121.0	130.0	106.8
5,000	45,000	19,350	157.2	121.0	130.0	106.8
5,000	50,000	21,500	157.2	121.0	130.0	106.8
5,000	55,000	23,650	157.2	121.0	130.0	106.8
5,000	60,000	25,800	157.2	121.0	130.0	106.8
5,000	65,000	27,950	157.2	121.0	130.0	106.8
5,000	70,000	30,100	157.2	121.0	130.0	106.8
5,000	75,000	32,250	160.3	122.3	131.3	108.1
5,000	80,000	34,400	160.3	122.3	131.3	108.1
5,000	85,000	36,550	160.3	122.3	131.3	108.1
5,000	90,000	38,700	160.6	122.4	131.4	108.2
5,000	95,000	40,850	160.9	122.5	131.5	108.3
5,000	100,000	43,000	160.9	122.5	131.5	108.3
5,000	105,000	45,150	160.9	122.5	131.5	108.3
5,000	110,000	47,300	160.9	122.5	131.5	108.3
5,000	115,000	49,450	160.9	122.5	131.5	108.3
5,000	120,000	51,600	160.9	122.5	131.5	108.3
5,000	125,000	53,750	160.9	122.5	131.5	108.3
5,000	130,000	55,900	160.9	122.5	131.5	108.3
5,000	135,000	58,050	160.9	122.5	131.5	108.3
5,000	140,000	60,200	160.9	122.5	131.5	108.3
5,000	145,000	62,350	160.9	122.5	131.5	108.3
5,000	150,000	64,500	160.9	122.5	131.5	108.3
5,000	155,000	66,650	161.2	122.7	131.7	108.5
5,000	160,000	68,800	162.2	123.1	132.1	108.9
5,000	165,000	70,950	162.2	123.1	132.1	108.9
5,000	170,000	73,100	162.2	123.1	132.1	108.9
5,000	175,000	75,250	162.2	123.1	132.1	108.9
5,000	180,000	77,400	162.2	123.1	132.1	108.9
5,000	185,000	79,550	163.1	123.5	132.5	109.3

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-19

ETBE delivered to California
Long Term
Tax credit for ethanol
U.S. ban of MTBE

Incremental Volume of ETBE	Total volume of ETBE	Ethanol feedstock volume	Ethanol cost	ETBE price	ETBE delivered price to California	Less subsidy
10,000	10,000	4,300	124.5	106.7	106.7	83.5
10,000	20,000	8,600	124.8	106.9	109.9	86.7
10,000	30,000	12,900	125.1	107.0	110.0	86.8
10,000	40,000	17,200	125.5	107.1	110.1	86.9
10,000	50,000	21,500	118.8	104.3	113.3	90.1
10,000	60,000	25,800	119.1	104.4	113.4	90.2
10,000	70,000	30,100	119.5	104.6	113.6	90.4
10,000	80,000	34,400	119.5	104.6	113.6	90.4
10,000	90,000	38,700	119.8	104.7	113.7	90.5
10,000	100,000	43,000	120.1	104.8	113.8	90.6
10,000	110,000	47,300	120.4	105.0	114.0	90.8
10,000	120,000	51,600	120.8	105.1	114.1	90.9
10,000	130,000	55,900	121.1	105.3	114.3	91.1
10,000	140,000	60,200	121.4	105.4	114.4	91.2
10,000	150,000	64,500	121.4	105.4	114.4	91.2
10,000	160,000	68,800	121.8	105.5	114.5	91.3
10,000	170,000	73,100	122.1	105.7	114.7	91.5
10,000	180,000	77,400	122.4	105.8	114.8	91.6

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-20

ETBE delivered to California
Intermediate Term
No tax credit for ethanol
U.S. ban of MTBE

Incremental Volume of ETBE	Total Volume of ETBE	Ethanol Feedstock	Ethanol Input Price	ETBE Price	Delivered Price to California
5,000	5,000	2,150	82.7	88.8	88.8
5,000	10,000	4,300	82.7	88.8	88.8
5,000	15,000	6,450	97.7	95.2	98.2
5,000	20,000	8,600	100.3	96.3	99.3
5,000	25,000	10,750	100.3	96.3	99.3
5,000	30,000	12,900	100.3	96.3	99.3
5,000	35,000	15,050	93.3	93.3	102.3
5,000	40,000	17,200	93.3	93.3	102.3
5,000	45,000	19,350	93.3	93.3	102.3
5,000	50,000	21,500	95.6	94.3	103.3
5,000	55,000	23,650	95.6	94.3	103.3
5,000	60,000	25,800	95.6	94.3	103.3
5,000	65,000	27,950	95.6	94.3	103.3
5,000	70,000	30,100	95.6	94.3	103.3
5,000	75,000	32,250	97.0	94.9	103.9
5,000	80,000	34,400	97.0	94.9	103.9
5,000	85,000	36,550	97.7	95.2	104.2
5,000	90,000	38,700	97.7	95.2	104.2
5,000	95,000	40,850	97.7	95.2	104.2
5,000	100,000	43,000	97.7	95.2	104.2
5,000	105,000	45,150	97.7	95.2	104.2
5,000	110,000	47,300	97.7	95.2	104.2
5,000	115,000	49,450	97.7	95.2	104.2
5,000	120,000	51,600	97.7	95.2	104.2
5,000	125,000	53,750	97.7	95.2	104.2
5,000	130,000	55,900	97.7	95.2	104.2
5,000	135,000	58,050	97.7	95.2	104.2
5,000	140,000	60,200	97.7	95.2	104.2
5,000	145,000	62,350	97.7	95.2	104.2
5,000	150,000	64,500	97.7	95.2	104.2
5,000	155,000	66,650	97.7	95.2	104.2
5,000	160,000	68,800	97.7	95.2	104.2
5,000	165,000	70,950	101.1	96.6	105.6
5,000	170,000	73,100	112.3	101.5	110.5
5,000	175,000	75,250	115.3	102.8	111.8
5,000	180,000	77,400	115.3	102.8	111.8

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-21

ETBE delivered to California
Long Term
No tax credit for ethanol
U.S. ban of MTBE

Incremental Volume of ETBE	Total Volume of ETBE	Ethanol Feedstock	Ethanol Input Price	ETBE Price	Delivered Price to
10,000	10,000	4,300	82.7	88.8	88.8
10,000	20,000	8,600	93.8	93.5	96.5
10,000	30,000	12,900	93.8	93.5	96.5
10,000	40,000	17,200	96.8	94.8	97.8
10,000	50,000	21,500	89.8	91.8	100.8
10,000	60,000	25,800	89.8	91.8	100.8
10,000	70,000	30,100	93.3	93.3	102.3
10,000	80,000	34,400	93.3	93.3	102.3
10,000	90,000	38,700	93.3	93.3	102.3
10,000	100,000	43,000	93.3	93.3	102.3
10,000	110,000	47,300	93.3	93.3	102.3
10,000	120,000	51,600	93.3	93.3	102.3
10,000	130,000	55,900	95.6	94.3	103.3
10,000	140,000	60,200	95.6	94.3	103.3
10,000	150,000	64,500	95.6	94.3	103.3
10,000	160,000	68,800	95.6	94.3	103.3
10,000	170,000	73,100	97.0	94.9	103.9
10,000	180,000	77,400	97.7	95.2	104.2

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-22

TAME delivered to California
Intermediate Term
U.S. ban of MTBE

Incremental Volume of TAME	Total Volume of TAME	Price	Price to California
5,100	5,100	78.2	78.2
2,300	7,400	78.2	96.4
4,784	12,184	78.7	97.6
9,350	21,534	78.7	94.4
15,610	37,144	80.1	98.1
1,500	38,644	80.1	97.1
2,572	41,216	80.1	100.1
5,603	46,819	80.1	100.1

Appendix M, con't: Alternate Oxygenate Supply Curves

Table M-23

TBA delivered to California
Intermediate Term
U.S. ban of MTBE

Incremental Volume	Total Volume	Price	Delivered price to California
10,160	10,160	77.4	77.4
14,400	24,560	79.5	82.5
10,000	34,560	79.5	87.5
10,000	44,560	79.5	87.5
10,000	54,560	81.6	89.6
10,000	64,560	81.9	89.9
10,000	74,560	81.9	89.9
10,000	84,560	81.9	89.9
10,000	94,560	81.9	89.9
10,000	104,560	82.7	90.7
10,000	114,560	82.7	90.7
10,000	124,560	83.3	91.3
10,000	134,560	83.3	91.3

Table M-24

TBA delivered to California
Long Term
U.S. ban of MTBE

Incremental Volume	Total Volume	Price	Delivered price to California
24,800	24,800	75.1	78.1
32,000	56,800	75.1	84.8
16,000	72,800	75.1	84.8
12,000	84,800	87.4	87.4
34,800	119,600	80.7	88.7

STAFF REPORT

SUPPLY AND COST OF ALTERNATIVES TO MTBE IN GASOLINE

TECHNICAL APPENDICES

Report on Tax Incentives For Ethanol

OCTOBER 1998

CALIFORNIA ENERGY COMMISSION

Pete Wilson, *Governor*

P300-98-013C

Evaluating the Cost and Supply of Alternatives to MTBE in California's Reformulated Gasoline

Project Report
Oxygenate Subcontractor

Task 3: Report on Tax Incentives for Ethanol

Prepared For the California Energy Commission

Under Subcontract No. CM60065W

October 15, 1998

BY:

Energy Security Analysis, Inc. (ESAI)
301 Edgewater Place, Suite 108
Wakefield, MA 01880

Introduction

Ethanol in the United States is subsidized by the Federal Government. The subsidy is not paid directly to companies that produce ethanol (except for the "small ethanol producers credit", see below). Rather, it generally accrues to companies that blend ethanol with gasoline, i.e., sellers of gasohol.

The result is that each gallon of ethanol that is blended with gasoline by a gasoline distributor or retailer results in a $.54 per gallon tax credit. As explained below, this credit can either be claimed as an excise tax exemption or an income tax credit. However, the distributor or retailer must have an income tax obligation during the year in order to claim the credit.

In all cases, to qualify for an excise tax exemption or an income tax credit, ethanol used as a motor fuel cannot be produced from petroleum, natural gas, coal, or peat. In other words, the ethanol must be biomass-derived.

Excise Tax Exemption [1]

Historically, the partial excise tax exemption has been much more important than the income tax credits in terms of the amount of tax benefits claimed. The current federal excise tax on gasoline is 18.4 cents per gallon.

The IRS refers to all blends of gasoline and ethanol as "gasohol" (For the purposes of this subsidy three discrete ethanol blends are allowed. They are: a 10 percent ethanol blend, 7.7 percent blend, and 5.7 percent blend). The partial excise tax exemption may be claimed by blenders of gasohol or by the distributors that sell them the gasoline used to make gasohol. The partial exemption may be claimed when the blenders or distributors file their quarterly federal excise tax returns (IRS Form 720), when blenders file their annual income tax returns, or, if certain conditions are met, when blenders file quarterly claims for refunds of excise taxes.

If a blender is claiming the partial tax exemption by selling gasohol, the blender claims the exemption based on the amount of ethanol present in the gasohol. The base exemption is for gasohol that contains 10 percent ethanol blended with 90 percent unleaded gasoline. This 10 percent ethanol blend is taxed at 13.0 cents per gallon, which is a 5.4 cents per gallon exemption from the federal tax of 18.4 cents per gallon. Gasohol that contains 7.7 percent or 5.7 percent ethanol is granted a tax exemption prorated from the base 5.4 cent exemption. In each case, the exemption equates to 54 cents per gallon of ethanol used [2]:

Ethanol blend per gallon gasohol	**Tax exemption per gallon of gasohol**	**Excise tax rate per gallon of gasohol**
10% blend	5.4 cents/gallon	13.0 cents/gallon
7.7% blend	4.158 cents/gallon (.77 * 5.4)	14.242 cents/gallon
5.7% blend	3.078 cents/gallon (.57 * 5.4)	15.322 cents/gallon

[1] Information on the excise tax exemption obtained from IRS Publication 510: "Excise Taxes for 1998; Fuel Taxes", and GAO Report No. 97-41, March 1997, "Report to the Chairman, Committee on Ways and Means, House of Representatives: Effects of the Alcohol Fuels Tax Incentives."
[2] See IRS Form 720, "Quarterly Federal Excise Tax Return"

If a gasoline distributor sells gasoline to a blender for use in blending with ethanol, the distributor claims an excise tax exemption on that portion of each gallon of gasoline that will be blended with ethanol. For example, if the gasoline is sold to a blender who will produce gasohol containing 10 percent ethanol, the excise tax on the gasoline is adjusted for the fact that only 90 percent of the gasoline sold is used in the final fuel mix (13 cents per gallon gasohol tax rate multiplied times 1/.90 equals an effective tax rate on gasoline of 14.444 cents per gallon, or an exemption of 3.956 cents per gallon). The rate for gasoline sold to create each ethanol blend is listed below. In all cases, the exemption equates to 54 cents per gallon of ethanol used[3]:

Gasoline Sold/Bought	**Tax exemption per gallon of gasoline**	**Excise tax per gallon of gasoline**
Gasoline sold or bought for producing gasohol containing at least 10% ethanol	3.956 cents/gallon	14.444 cents/gallon (13.0 * 1/.90)
Gasoline sold or bought for producing gasohol containing at least 7.7% ethanol	2.970 cents/gallon	15.430 cents/gallon (14.242 * 1/.923)
Gasoline sold or bought for producing gasohol containing at least 5.7% ethanol	2.152 cents/gallon	16.248 cents/gallon (15.322 * 1/.943)

This partial tax exemption lowers the after-tax cost of the gasoline that fuel blenders mix with ethanol. Distributors that claim the tax exemption will reduce the price of the gasoline they sell to ethanol blenders by the amount of the tax reduction (distributors are just as well off selling gasoline at a lower price and receiving a tax exemption as they are selling gasoline at a higher price and receiving no exemption).

Gasohol blenders can also claim a refund of the overpayment of the excise tax on gasoline sold to them by a distributor if that gasoline was sold without a tax reduction.

Income Tax Credit[4]

The ethanol subsidy may also be claimed via an income tax credit. There are three credits that can be claimed against the federal income tax. Each of the tax credits is aimed at a distinct type of business:

[3] Ibid.

[4] Information on the income tax credit obtained from IRS Publication 510: "Excise Taxes for 1998; Fuel Taxes", and GAO Report No. 97-41, March 1997, "Report to the Chairman, Committee on Ways and Means, House of Representatives: Effects of the Alcohol Fuels Tax Incentives."

1. The "alcohol mixtures credit": This credit allows businesses that mix ethanol with other motor fuels and use the blend in a trade or business or sell the blend as fuel. The credit allows the blenders to reduce their income taxes by 54 cents for each gallon of biomass ethanol used in their blended fuel. The ethanol must be at least 190 proof for the full 54 cent per gallon credit. Alcohol that is between 150 and 190 proof is eligible for a 45 cent per gallon credit. No credit is available for alcohol that is less than 150 proof.

2. The "alcohol credit": This credit allows businesses to reduce their income taxes by 54 cents for each gallon of neat biomass ethanol fuel that they sell at the retail level or use themselves in their trade or business. Straight alcohol sold at the retail level is placed directly in the fuel tank of the buyer's vehicle and is not mixed with any other fuel.

3. The "small ethanol producers credit": This credit allows businesses that produce less than 15 million gallons of ethanol for fuel each year to reduce their income taxes by 10 cents for each gallon produced. The ethanol must be used or sold for use as a motor fuel.

Note on Income Tax Credits

At the time the income tax credits were instituted, only the excise tax exemption existed as a way to claim the ethanol subsidy, and the exemption at the time only applied to 10 percent ethanol blends. Congress wished to allow blenders to mix ethanol at blends lower than 10 percent and still be eligible for the subsidy. Also, Congress wished to grant the incentives to ethanol users who were exempt from excise taxes, such as farmers. Thus the income tax credits were created as an extension and broadening of the ethanol tax subsidy.

Status of ETBE

In 1990, final federal regulations provided that ethanol used for producing ethyl tertiary butyl ether (ETBE) generally is treated as alcohol for purposes of the "alcohol mixtures" income tax credit when the ETBE is mixed with gasoline. In 1993, final regulations accepted gasoline and ETBE blends as qualifying for the partial exemption from the gasoline excise tax, effective October 1, 1995. These regulations stipulated that gasoline refiners could claim the partial exemption for gasoline/ETBE blends that are blended inside the refinery gate and then distributed to bulk terminals. For example, a gasoline/ETBE mixture would qualify as 5.7 percent gasohol if the mixture contains 12.7 percent ETBE and each gallon of ETBE is made from .45 gallon of ethanol. [5]

ETBE blend per gallon gasoline	**Tax exemption per gallon of ETBE blended gasoline**	**Excise tax rate per gallon of ETBE blended gasoline**
17.1% blend (equivalent to 7.7 % ethanol blend)	4.158 cents/gallon (.77 * 5.4)	14.242 cents/gallon
12.7% blend (equivalent to 5.7 % ethanol blend)	3.078 cents/gallon (.57 * 5.4)	15.322 cents/gallon

[5] Federal Register, Volume 59, October 19, 1994: "Gasoline and Diesel Fuel Excise Tax; Rules Relating to Gasohol; Tax on Compressed Natural Gas."

ETBE does not commingle with water as ethanol does. However, when a gasoline/ETBE blend is produced inside the refinery gate and then transported via pipeline to the terminal rack, some of the alcohol content (the ethanol derived ether) may have been diluted with non-qualifying blends because of the use of common-carrier pipelines, barges, and non-segregated storage facilities. As a result, the gasoline/ETBE blend removed at the terminal rack may not qualify for the reduction from the regular tax rate for gasoline due to commingling between the refinery and terminal rack. Federal regulations stipulate that gasoline that does not contain the required volume of ethanol cannot qualify for tax incentives.

Final federal regulations resolved this issue in the following way. Ordinarily, federal regulations provide that the bulk removal of gasoline by an IRS-registered refiner for delivery to a terminal operated by an IRS-registered terminal operator is not subject to the federal excise tax. However, the regulations were changed so that refiners registered by the IRS could designate themselves as "not registered" for the bulk removal of "gasohol" (in this case, gasoline blended with ETBE). In this way, the refiner will be liable for the excise tax, but because it is considered "gasohol" it is eligible for a reduced rate. The final regulations also provide that the refiner is not required to deposit this tax before filing the return relating to that tax. The ETBE/gasoline blend will be taxed at the full rate when it is removed from the terminal rack, but the position holder at this time can apply for a refund on this second tax.[6]

How Blenders/Producers Benefit from Tax Incentives

The tax incentives described above allow ethanol to be priced competitively with gasoline and MTBE, which are substitutes for ethanol, despite the fact that the cost of production for ethanol is higher than these fuels. Since the incentives are equal to 54 cents per gallon of ethanol, the effective or after tax price that the ethanol blender receives for ethanol is 54 cents less than the price at which ethanol is sold by the alcohol producer. In other words, producers can charge a price for ethanol that is high enough to cover the cost of production, while blenders buy alcohol at a price that is competitive with gasoline and MTBE.

Summary

In summary, the ethanol subsidy is accomplished in two ways:

1. by granting a 5.4 cent per gallon partial excise tax exemption for gasohol fuels, and
2. by allowing a 54 cent per gallon income tax credit for ethanol used as a fuel.

The EXCISE TAX exemption is available to taxpayers who:

1. Are liable for the tax on the removal or entry of gasohol (including blends less than 10% ethanol), or
2. Are liable for the tax on the removal or entry of gasoline used to make gasohol

[6] Federal Register, Volume 60, August 7, 1995: "Gasohol; Compressed Natural Gas."

The INCOME TAX credit is available to taxpayers who:

1. produce or blend an alcohol/fuel mixture, or
2. sell or use for business 100% straight alcohol actually placed in the vehicle's fuel supply tank by the taxpayer.

STAFF REPORT

SUPPLY AND COST OF ALTERNATIVES TO MTBE IN GASOLINE

TECHNICAL APPENDICES

External CARB Gasoline Supply

OCTOBER 1998

CALIFORNIA ENERGY COMMISSION

Pete Wilson, *Governor*

P300-98-013D

EXTERNAL CARB GASOLINE SUPPLY

Prepared For:

ACUREX ENVIRONMENTAL CORPORATION
AND
CALIFORNIA ENERGY COMMISSION

Prepared By:

P

Dallas - Houston - Los Angeles
Calgary - London
Buenos Aires - Singapore

October 1998/Revision 1

John H. Vautrain

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1. INTRODUCTION

1.1 PARTIES

Purvin & Gertz, Inc., (Purvin & Gertz), was retained by Acurex Environmental Corporation (Acurex) on behalf of the California Energy Commission (CEC) to provide evaluations and assistance related to the proposed MTBE ban in California. Purvin & Gertz was retained to provide four deliverables: a presentation at a public workshop, a report on the supply costs of CARB gasoline and blend stocks from outside California, a report on the marine terminal infrastructure and associated limitations, and compilation of the final report combining Purvin & Gertz work with that of other consultants. This document is the report describing the supply costs of CARB gasoline and blend stocks from outside California.

This report has been prepared for the sole benefit of the CEC. Any third party in possession of the report may not rely upon its conclusions without the written consent of Purvin & Gertz.

Purvin & Gertz conducted this analysis and prepared this report utilizing reasonable care and skill in applying methods of analysis consistent with normal industry practice. All results are based on information available at the time of review. Changes in factors upon which the review is based could affect the results. Forecasts are inherently uncertain because of events or combinations of events which cannot reasonably be foreseen including the actions of government, individuals, third parties and competitors. ***NO IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE SHALL APPLY.***

Some of the information on which this report is based has been provided by others. Purvin & Gertz has utilized such information without verification unless specifically noted otherwise. Purvin & Gertz accepts no liability for errors or inaccuracies in information provided by others.

Two other consultants, Mathpro, Inc. (Mathpro) and Energy Security Analysis, Inc. (ESAI) are preparing parallel reports on other aspects of the MTBE ban under separate contracts with Acurex. Although the goals of the work are joint, the three consultants, Purvin & Gertz, Mathpro and ESAI, are working independently and none is responsible for the work or results of another. Neither Mathpro nor ESAI is responsible for any results presented in this report.

1.2 PURPOSE AND BACKGROUND

There are legislative proposals in California which would ban or restrict the use of MTBE as a gasoline blending component. MTBE is widely used in California as part of refiners' efforts to comply with reformulated gasoline requirements imposed by the U.S. Environmental Protection Agency (EPA) and the California Air Resources Board (CARB). The California legislature has determined that prior to considering a ban or restriction on

the use of MTBE as a gasoline component, CEC should study possible impacts on the supply and cost of gasoline in California.

Three contractors were selected to participate with CEC in the study. Mathpro was chosen to prepare linear program (LP) models of the California refining industry. These models were to be used by Mathpro to estimate the capabilities of the refineries to produce CARB gasoline under a variety of scenarios and to estimate the capital and operating changes that would occur in the event that MTBE is banned or restricted under a variety of scenarios. ESAI was retained to identify the supply costs of various oxygenate materials as alternatives to MTBE. The results of this report by Purvin & Gertz would be combined with results from ESAI by Mathpro as part of its LP analysis of the California refining industry. Purvin & Gertz was chosen to combine the results determined by Mathpro and ESAI into a final report for CEC reflecting the opinions of each of the individual consultants. The scope of this study is limited to costs of external supplies of CARBOB. Price impacts on other markets, the adequacy of marine infrastructure costs to manufacture CARBOB within the state, oxygenate supply and cost issues and price impacts to the consumer are covered in separate documents.

Policy recommendations regarding the path which should be followed with respect to the MTBE ban or restriction are to be made by CEC. Purvin & Gertz makes no recommendation in this report whether any particular policy option is superior to another. The scopes of the reports of the consultants are confined to expert opinions of cost and supply impacts. CEC is responsible for making any policy recommendations after giving appropriate consideration to the reports of the consultants as well as to other information as may be deemed appropriate by CEC.

1.3 SCENARIOS AND ASSUMPTIONS

The CEC effort encompasses many alternative cases so that each logical oxygenate is reviewed and important legislative/regulatory alternatives are considered.

All of the cases evaluated in this study involve preparation of a CARB gasoline blend stock in the distant location that could be shipped to California for further blending with the selected oxygenate. This oxygenate-free material is referred to as “CARBOB”. The CARBOB would be combined with the oxygenate material, ethanol, ETBE, TAME, or TBA, after arrival in California. In our analysis we considered the quality of the final blend of the CARBOB and the oxygenate to assure that the mixture would meet CARB gasoline specifications.

The CEC study includes effects of both a California-only MTBE ban as well as a nationwide MTBE ban. The range of cases considered is as shown below:

Oxygenate	**Regulatory Change**
Ethanol	None
Ethanol	1 PSI RVP Waiver
ETBE	None
TBA	None
Mixed Oxygenates	None
None	HR 630

The underlying assumption in all the cases is that MTBE would be banned. There is no assumption of a mandate to use any specific oxygenate in any case. The oxygenate alternatives were evaluated individually for purposes of clearly identifying costs and not as a suggestion that banning MTBE implies a mandate to use any particular oxygenate in its place.

Ethanol was evaluated in two ways. First, ethanol was evaluated using all existing regulations. Second, ethanol was evaluated in the context of a one psi waiver of the Reid Vapor Pressure (RVP) specification provided ethanol is blended at 10% by volume.

Three other oxygenate cases were considered: ETBE, TBA and mixed oxygenates. It was considered likely that adequate ETBE or TBA capacity could be developed to allow these materials to be produced to satisfy California requirements at some reasonable cost. The mixed oxygenate case is based on an open mixture of materials including TBA, ETBE, TAME and DIPE. The supplies of TAME or DIPE alone were thought not to be likely to be adequate to meet all of California's requirements in any reasonable case and therefore these oxygenates were evaluated together with others on a mixed basis.

Finally, a case was evaluated in which no oxygenate at all was required. Since federal laws and regulations as well as state laws and regulations govern the oxygen content of a large fraction of California's gasoline, modifications to federally-imposed requirements would need to be made as a precondition to producing California's gasoline supply as anticipated by this case.

There may be air quality and other costs or benefits associated with one oxygenate or another or one or more of the regulatory modifications reflected in these cases. This study does not purport to evaluate any of those costs or benefits. The scope of the study is limited to identifying sources and costs of accessing supplies of fuels of various types.

2. SUMMARY

2.1 METHODOLOGY

The methodology used to determine CARBOB supply curves is based on relating CARBOB producibility in each of seven regions of the world to characteristics of the more suitable refineries in that region. Refineries were evaluated using a “CARB Index” which measures the presence of the types of refinery process equipment that are commonly found useful for making CARB gasoline. Only those refineries with the highest probability of making commercial quantities of CARBOB were evaluated further.

CARBOB production volume was established based on evaluating recombinations of existing refinery gasoline streams rather than on fundamental reorientations of refinery operations. The least expensive way for refineries to produce a new product typically would be to select suitable materials from those already produced and simply blend the new product using different recipes than those that had been used in the past. Some volume of CARBOB can be produced in this way. A higher cost method would be to select different crude oils for the refinery that were more suitable to the new product or to alter refinery operating practices to produce more of the new product. An even more costly and time consuming procedure would be to make capital improvements at the refinery that would improve the ability of the refinery to transform any given crude oil into the new product. This last and most extreme method would usually be justified only if a large volume of the product were to be required, more than could be accomplished by the first two methods, if the requirement were to be long term or if the product is particularly valuable so the cost of the capital could be recovered. In this report, only the first type of procedure is considered. In using this method, only the least expensive increments of production were identified. In the event that this volume were inadequate to meet the need, then more expensive and extreme steps would have to be anticipated but as this report will show, these less expensive steps were adequate to identify reasonable volumes of supply.

For the CARBOB-Capable group in each region, an estimate was made of the amount of alkylate that could be diverted to manufacturing CARBOB. Alkylate is a relatively costly refinery product that can be used to produce high value premium gasolines and aviation fuels. Refiners would be unwilling to release all of their alkylate production because of other high value uses.

Based on typical gasoline blend stock qualities for each region and the requirements of the predictive model, the amount of CARBOB that could be blended from a given volume of alkylate was estimated. Combining these ratios with the amount of alkylate that is estimated to be available resulted in the volume of CARBOB that could be produced in each region.

The cost of producing CARBOB from each region of the world was based on a buildup of costs by type. Based on historical summer 1997 data, the prevailing gasoline price in each

region of the world was established. The opportunity costs of producing some gasoline to CARBOB required specifications and an allowance for ancillary costs were estimated. The costs to ship the product to California including time value of holding inventory, direct shipping costs, and terminaling charges in California were estimated. Provision was made for refiner incentive over and above cost recovery.

Combining the cost and volume data for each region of the world resulted in a supply cost curve for CARBOB. The results vary depending on some of the scenarios used. There is inevitable uncertainty associated with determining supply curves in this manner that results from future regulatory changes in supply areas, commercial factors related to contracting for CARBOB supplies, fluctuations in refinery operations and other factors. The risk that supply would actually be available increases at higher supply levels.

2.2 REFINING CAPACITY

There are approximately 730 refineries with about 76 million barrels per day of capacity in the world outside California. These refineries produce about 17 million barrels per day of gasoline. These refineries were grouped by region and each region was segregated into two classes: those refineries with configuration characteristics consistent with some possibility of manufacturing commercial quantities of CARBOB and those lacking those characteristics. Table 2.2-1 summarizes the results of these analyses.

TABLE 2.2-1
REFINERY CAPACITY
(Barrels per Stream Day)

	Total		CARB Capable		CARB Incapable	
	Refineries	Capacity	Refineries	Capacity	Refineries	Capacity
Pacific North West	5	575,350	1	108,200	4	467,150
U.S. Gulf Coast (USGC)	56	7,005,515	29	6,027,350	27	978,165
Caribbean	14	1,733,900	2	865,000	12	868,900
Europe	108	14,374,735	19	3,742,850	89	10,631,885
Latin America	66	5,796,143	5	1,457,325	61	4,338,818
Middle East	46	5,756,290	2	580,600	44	5,175,690
Far East	176	17,707,312	16	4,094,236	160	13,613,076
Other	255	23,037,723	42	7,136,388	213	15,901,335
TOTAL	**726**	**75,986,968**	**116**	**24,011,949**	**610**	**51,975,019**

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2.3 ALKYLATE AVAILABILITY

Some of the alkylate produced by CARBOB-Capable refineries could be made available for blending CARBOB. Not all the alkylate from these refineries could be made available because of other requirements for alkylate. Alkylate is an important component of EPA-reformulated gasoline produced on the U.S. Gulf Coast (USGC) and is a component of

high-value premium gasolines as well as aviation gasolines produced in all regions of the world.

Alkylate availability is not influenced by the selection of which oxygenate is assumed to be used in California. The influence of oxygenate selection is confined to the gasoline blending which can occur using the released alkylate. Hence there are only two cases for alkylate supply, a California-only MTBE ban and the nation-wide MTBE ban.

Based on discussions held with refiners and consideration of the other requirements for alkylate, a set of alkylate availabilities was prepared.

Table 2.3-1 shows the total amount of alkylate estimated to be available from each region of the world.

TABLE 2.3-1
ALKYLATE AVAILABILITY
(Barrels per Stream Day)

	Alkylate Capacity	Alkylate Availability	
		California MTBE Ban	Nationwide MTBE Ban
Pacific North West	12,000	4,000	4,000
U.S. Gulf Coast	503,000	86,000	43,000
Caribbean	22,000	11,000	11,000
Europe	158,000	27,000	27,000
Latin America	84,000	25,000	25,000
Middle East	27,000	8,000	8,000
Far East	85,000	14,000	14,000
TOTAL	**891,000**	**175,000**	**132,000**

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In most parts of the world, the availability of alkylate is not directly influenced by whether an MTBE ban is imposed in California only or on a nation-wide basis in the U.S. It has been assumed that there is no ban in other countries in either case. In the Pacific North West, an MTBE ban would not be expected to affect summertime alkylate supplies. Only in the USGC there would be a significant influence on alkylate supplies because of a relative octane shortfall that could accompany a nation-wide ban.

As with most refinery intermediates and blendstocks, there is little trade in alkylate. Consequently, while it is considered reasonable that refiners should be able to release such quantities of alkylate as shown in Table 2.3-1, there is greater probability with respect to neat alkylate than there is with finished CARBOB that refiners would be reluctant to release these volumes in regular practice. Hence, these volumes will be used directly to calculate CARBOB availabilities but it would be prudent to limit expectations for purchased alkylate to a lower value of 100,000 barrels per day in the California only ban cases and 75,000 barrels per day in the nation-wide MTBE ban cases.

2.4 CARBOB/ALKYLATE RATIOS

Manufacturing CARBOB involves blending with alkylate other refinery gasoline streams of varying qualities. The combination of these streams must, when mixed with the oxygenate, meet CARB gasoline specifications. CARB specifications may be met by any of three methods: flat limits, averaging limits, or predictive model. The predictive model is the most flexible method and tends to maximize supplies of CARB gasoline from any set of blend stocks. The ability of external refineries to produce CARBOB from alkylate was evaluated in light of the predictive model.

All the CARB specification alternatives involve evaluating many gasoline properties that are not well-reported around the world. Furthermore, there is some danger of over-optimizing the gasoline blending. In light of the quality of the available data as well as to reduce the danger of over-optimization, refinery regions were assigned to CARBOB/Alkylate ratio classes.

The CARBOB/Alkylate ratio representative of each class was evaluated by using the predictive model and typical gasoline blend stock qualities. Under normal circumstances at least one to two barrels of other blend stocks could be combined with one barrel of alkylate and meet CARBOB requirements. If refineries have reasonable levels of control of benzene and sulfur in blend stocks, then blending two to three barrels of other blend stocks with one barrel of alkylate is quite reasonable. If refineries have superior control of contaminants then perhaps four to six barrels of other blend stocks can be combined with one barrel of alkylate. The California refiners as a group operate in this upper range. Table 2.4-1 shows the CARBOB/Alkylate ratios used for each class.

TABLE 2.4-1
CARBOB/ALKYLATE RATIO CLASSES

Low	2.5
Medium	3.5
High	5.5

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Each region and case was evaluated to determine the appropriate CARBOB/Alkylate class. Table 2.4-2 shows the matrix of cases and classes that were used.

TABLE 2.4-2
CARBOB/ALKYLATE RATIO CLASS ASSIGNMENTS

	Ethanol No Waiver	Ethanol Waiver	TBA	ETBE	Mixed Oxygenates	No Oxygenate
Pacific North West	Low	Low	Medium	Medium	Medium	Low
U.S. Gulf Coast	Low	Low	High	High	High	Low
Caribbean	Low	Low	Low	Low	Low	Low
Europe	Low	Low	High	High	High	Low
Latin America	Low	Low	Low	Low	Low	Low
Middle East	Low	Low	Low	Low	Low	Low
Far East	Low	Low	Low	Low	Low	Low

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Reviewing Table 2.4-2 shows that the number of different solutions is not as large as the number of cases. Blending ethanol with no RVP waiver or with a waiver but at the 10% level imposes restrictions on refiners that often lead to appreciably less CARBOB availability. The same difficulty is encountered in the no oxygenate case. The CARBOB/Alkylate ratio classes are the same whether the refiners are blending TAME, ETBE, TBA, or mixed oxygenates. There would still be some difference in CARB gasoline supply due to variations in the amount of oxygenate required to be blended with the CARBOB.

2.5 COSTS OF SUPPLY

Supply costs were estimated starting with the prevailing price of gasoline in each market in the summer of 1997. The prevailing price of gasoline in each market as represented by the spot price is viewed as the alternative value of the blend stocks diverted to CARBOB production. A cost element for direct processing costs was added. This cost is reflective mostly of the opportunity to blend low cost butane with gasoline which is lost due to the lower vapor pressure required to meet CARB specifications. A provision of 0.5 cents per gallon of CARBOB was made for incidental direct costs such as costs to clear tankage, extra laboratory testing, any extra energy costs that might be related to more severe debutanization and the like. Octane credit is a negative cost element which captures the unusually low octane to which CARBOB can be produced. The oxygenate with which CARBOB is blended provides several octane numbers in most cases. A provision was made for the extra costs to hold inventory including the time value of money incurred during shipping and any cargo consolidation costs at the port of origin. Transportation costs were determined based on Worldscale quotes for appropriately sized tankers on international voyages and industry data for domestic voyages. A provision was made for terminaling costs in California of 0.75 cents per gallon of CARBOB. A refiner margin of two cents per gallon was added to reflect the need for reasonable profit to induce refiners in distant locations to undertake the effort of making CARBOB.

None of these cost elements are sensitive to which oxygenate is under consideration except for the processing costs and the octane credit. Processing cost varies because the vapor pressure of the oxygenates is different. Likewise the amount of octane credit

available depends on which oxygenate is used. Because the cost of only CARBOB and not finished CARB gasoline is being determined, the cost figures are not sensitive to oxygenate costs.

There is some risk that delivering large volumes of CARBOB, alkylate, or other products to California and that shipping large volumes of non-CARB gasoline or intermediates away from California might disrupt typically observed ship availabilities or costs. Since such trade would be a very small fraction of international clean products movements, such risk for international origins or destinations is considered small. Domestic shipments would need to be moved using Jones Act carriers, the supply of which is much smaller. In the long term, it would be possible, if appropriate contracts for use were in place, to build new Jones Act carriers, or possibly even to reconfigure the domestic pipeline system to accommodate some shipments. In the intermediate term, there would not be adequate time to build new tankers and a Jones Act carrier shortfall could influence CARBOB or alkylate supply patterns. In the event of a shortage of carriers, less efficient and more costly foreign sources might be preferred.

2.6 SUPPLY CURVES

Table 2.6-1 shows the CARBOB supply curve for the California only MTBE ban. Each increment of supply represents the supply from a region at the cost associated with that region. The volume available from various sources is dependent on the availability of the alkylate and the CARBOB/Alkylate ratio assigned to that region.

Table 2.6-2 shows the CARBOB supply curve for the nation-wide MTBE ban case. The principal difference in these cases is the lowered availability from the USGC which occurs because more Gulf Coast alkylate must be retained to meet challenges of an MTBE ban east of the Rockies.

For reference, the average summertime 1997 spot price of CARB reformulated gasoline is estimated to have been 63.7 cents per gallon. The historical CARB reformulated gasoline price is not comparable to the CARBOB prices because the CARBOB must in most cases be blended with an oxygenate to produce CARB reformulated gasoline. The costs of that blending are not in this study.

TABLE 2.6-3
EXTERNAL ALKYLATE SUPPLIES
CALIFORNIA ONLY MTBE BAN

Region	Cost ¢/Gal	Volumes, B/D Region	Volumes, B/D Cumulative
Europe	77.0	27,000	27,000
Caribbean	78.4	11,000	38,000
Latin America	78.1	25,000	63,000
Pacific North West	79.7	4,000	67,000
Far East	81.4	14,000	81,000
U.S. Gulf Coast	81.5	86,000	167,000
Middle East	82.1	8,000	175,000

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Table 2.6-3 shows the alkylate supply curve for all cases involving a California-only MTBE ban. To the extent that alkylate is delivered to California, there is less alkylate available to manufacture CARBOB in the exporting region. Table 2.6-4 shows the alkylate supply curve for all cases involving the nation-wide MTBE ban.

TABLE 2.6-4
EXTERNAL ALKYLATE SUPPLIES
US WIDE MTBE BAN

Region	Cost ¢/Gal	Volumes, B/D Region	Volumes, B/D Cumulative
Europe	77.0	27,000	27,000
Caribbean	78.4	11,000	38,000
Latin America	78.1	25,000	63,000
Pacific North West	79.7	4,000	67,000
Far East	81.4	14,000	81,000
U.S. Gulf Coast	81.5	43,000	124,000
Middle East	82.1	8,000	132,000

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Uncertainty is associated with the alkylate availability for the same reasons as for the CARBOB as discussed above. Furthermore, trade in refinery intermediates is considered to carry more supply risk than trade in finished products and competing buyers for available supplies may exist or develop. Consequently, notwithstanding that the supply curves extend to the values shown in Table 2.3-1, it is recommended that limits of 100,000 barrels per day for the California only MTBE ban and 75,000 barrels per day for the U.S.-wide MTBE ban be adopted for refinery modeling purposes.

TABLE 2.6-1
SUPPLY CURVE
EXTERNAL CARBOB SUPPLIES - CALIFORNIA ONLY MTBE BAN

		Ethanol (No Waiver)				Ethanol (Waiver)				Mixed Oxygenates	
	Cost	Volumes, B/D			Cost	Volumes, B/D			Cost	Volumes, B/D	
Region	¢/Gal	Region	Cumulative	Region	¢/Gal	Region	Cumulative	Region	¢/Gal	Region	Cumulative
Europe	68.7	67,000	67,000	Europe	67.2	67,000	67,000	Europe	67.5	148,000	148,000
Latin America	68.8	63,000	130,000	Latin America	67.4	63,000	130,000	Latin America	67.8	63,000	211,000
Caribbean	69.3	26,000	156,000	Caribbean	67.8	26,000	156,000	Caribbean	68.2	26,000	237,000
U.S. Gulf Coast	72.5	214,000	370,000	U.S. Gulf Coast	71.0	214,000	370,000	U.S. Gulf Coast	71.3	470,000	707,000
Pacific North West	72.9	10,000	380,000	Pacific North West	71.2	10,000	380,000	Pacific North West	71.6	14,000	721,000
Middle East	73.0	21,000	401,000	Middle East	71.5	21,000	401,000	Middle East	71.9	21,000	742,000
Far East	73.7	34,000	435,000	Far East	72.5	34,000	435,000	Far East	72.8	34,000	776,000

		TBA				ETBE				No Oxygenates	
	Cost	Volumes, B/D			Cost	Volumes, B/D			Cost	Volumes, B/D	
Region	¢/Gal	Region	Cumulative	Region	¢/Gal	Region	Cumulative	Region	¢/Gal	Region	Cumulative
Europe	68.2	148,000	148,000	Europe	66.8	148,000	148,000	Europe	68.8	67,000	67,000
Latin America	68.4	63,000	211,000	Latin America	67.1	63,000	211,000	Latin America	69.0	63,000	130,000
Caribbean	68.9	26,000	237,000	Caribbean	67.4	26,000	237,000	Caribbean	69.4	26,000	156,000
U.S. Gulf Coast	72.0	470,000	707,000	U.S. Gulf Coast	70.6	470,000	707,000	U.S. Gulf Coast	72.6	214,000	370,000
Pacific North West	72.3	14,000	721,000	Pacific North West	70.6	14,000	721,000	Pacific North West	72.8	10,000	380,000
Middle East	72.6	21,000	742,000	Middle East	71.1	21,000	742,000	Far East	73.0	34,000	414,000
Far East	73.5	34,000	776,000	Far East	72.0	34,000	776,000	Middle East	73.1	21,000	435,000

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TABLE 2.6-2
SUPPLY CURVE
EXTERNAL CARBOB SUPPLIES - US WIDE MTBE BAN

		Ethanol (No Waiver)				Ethanol (Waiver)				Mixed Oxygenates	
	Cost	Volumes, B/D			Cost	Volumes, B/D			Cost	Volumes, B/D	
Region	¢/Gal	Region	Cumulative	Region	¢/Gal	Region	Cumulative	Region	¢/Gal	Region	Cumulative
Europe	68.7	67,000	67,000	Europe	67.2	67,000	67,000	Europe	67.5	148,000	148,000
Latin America	68.8	63,000	130,000	Latin America	67.4	63,000	130,000	Latin America	67.8	63,000	211,000
Caribbean	69.3	26,000	156,000	Caribbean	67.8	26,000	156,000	Caribbean	68.2	26,000	237,000
U.S. Gulf Coast	72.5	107,000	263,000	Pacific North West	71.0	10,000	166,000	Pacific North West	71.3	14,000	251,000
Pacific North West	72.9	10,000	273,000	U.S. Gulf Coast	71.2	107,000	273,000	U.S. Gulf Coast	71.6	235,000	486,000
Middle East	73.0	21,000	294,000	Middle East	71.5	21,000	294,000	Middle East	71.9	21,000	507,000
Far East	73.7	34,000	328,000	Far East	72.5	34,000	328,000	Far East	72.8	34,000	541,000

		TBA				ETBE				No Oxygenates	
	Cost	Volumes, B/D			Cost	Volumes, B/D			Cost	Volumes, B/D	
Region	¢/Gal	Region	Cumulative	Region	¢/Gal	Region	Cumulative	Region	¢/Gal	Region	Cumulative
Europe	68.2	148,000	148,000	Europe	66.8	148,000	148,000	Europe	68.8	67,000	67,000
Latin America	68.4	63,000	211,000	Latin America	67.1	63,000	211,000	Latin America	69.0	63,000	130,000
Caribbean	68.9	26,000	237,000	Caribbean	67.4	26,000	237,000	Caribbean	69.4	26,000	156,000
U.S. Gulf Coast	72.0	235,000	472,000	Pacific North West	70.6	14,000	251,000	Far East	72.6	34,000	190,000
Pacific North West	72.3	14,000	486,000	U.S. Gulf Coast	70.6	235,000	486,000	Pacific North West	72.8	10,000	200,000
Middle East	72.6	21,000	507,000	Middle East	71.1	21,000	507,000	Middle East	73.0	21,000	221,000
Far East	73.5	34,000	541,000	Far East	72.0	34,000	541,000	U.S. Gulf Coast	73.1	107,000	328,000

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3. METHODOLOGY

This section presents the basic methodology that was used to estimate supply costs for CARBOB from outside California. The goal of this study is to evaluate the supply curve for CARBOB to California. Based on preliminary work prepared by CEC as well as comments by refining industry representatives, it is anticipated that in many cases California refineries could find the ability to meet CARB specifications reduced without MTBE. Since California consumes about 900,000 barrels per day of gasoline and part of that fuel is expected to be supplied by the California refineries, the external supply range of greatest interest is zero to several hundred thousand barrels per day.

There are about 750 refineries in the world with a total capacity of about 78 million barrels per day. The world's refineries vary extremely widely in feed stocks, operating goals, level of process sophistication and prevailing product specifications. Some refineries are simple topping plants that do little more than separate components naturally occurring in local crude oils into products. Such plants either do not produce gasoline or use tetra-ethyl lead or similar compounds to produce gasoline. The gasoline produced might be of very low octane, unsuitable for modern high-performance engines such as those found in the California automotive fleet. Most of the other refineries that produce gasoline rely primarily on processes like reforming that produce gasolines similar to those found in the U.S. twenty years ago. A few refineries are very highly sophisticated producing high quality products similar to CARB gasoline from a variety of crude oil types. Most of the refineries in the world are expected to be irrelevant to external CARBOB supplies and only a fraction of the world refineries will contribute to such supplies.

California's gasoline requirements are very small compared to world petroleum markets. The world's refineries produce about 17 million barrels per day of gasoline and total products of about 70 million barrels per day. The supply volume of interest to this study is perhaps one to three percent of total world gasoline output or substantially below one percent of total world refined products output.

Opportunistic blending is the most likely method to be used for producing external CARBOB supplies. In the event that MTBE is banned in California and refineries outside the state are called on to supply CARBOB to the state, it is considered unlikely that distant refineries would make substantial investments to provide the fuel or reorient their operations toward supplying the distant market. Historically the U.S. West Coast has been a geographically isolated and fairly self-sufficient market accepting only small volumes of imports. From a real-world perspective, it is more likely that refineries already possessing useful blend stocks in reasonable volumes would either produce the fuel from those available blend stocks or would sell blend stocks to intermediaries who would aggregate such stocks from various refiners into commercial scale cargoes meeting applicable specifications.

The very small proportion of total refined products output that would be desired for California indicates that a refinery modeling technique relying on aggregations of large

numbers of refineries would be unreliable for evaluating supply costs. Such techniques would be subject to over-optimization for which no practical and reliable correction has been identified. Because of the large number of refineries it was impractical to model each refinery or even small groups of refineries. Finally, because the real world response to the possible supply problems posed by an MTBE ban is more likely to be one of opportunistic blending rather than fundamental shifts in refinery operations, approaches to supply cost estimation based on shifts in operations are considered to be impractical.

The technique chosen to resolve the problem is based on estimating the opportunity cost of diverting high quality blend stocks to producing CARBOB for California rather than conventional products for local markets. To the opportunity cost of the blend stocks, estimates of identifiable additional direct costs as well as refiner incentive have been added. Differences among opportunity costs from different areas of the world result from different prevailing prices in those areas. Direct cost differences can arise from transportation cost differences and other similar factors. The major steps in the analysis are outlined in this chapter.

3.1 DIVISION OF WORLD INTO REGIONS

The world was divided into seven regions that may have some capability to provide CARBOB to California. These regions were defined by CEC at the outset of the study. Table 3.1-1 lists the regions which were considered:

TABLE 3.1-1
WORLD SUPPLY REGIONS

Pacific North West
United States Gulf Coast (USGC)
Caribbean
Europe
Latin America
Middle East
Far East

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The Pacific North West includes all the refineries within the state of Washington that can make gasoline. There are no refineries in Oregon that can make gasoline of any type.

The USGC includes the refineries in Petroleum Administration for Defense District (PADD) III. PADD III includes Texas, Louisiana, Mississippi, New Mexico and Alabama.

Caribbean includes the refineries in the U.S. Virgin Islands, Puerto Rico and island nations in the Caribbean. Caribbean has been defined to include refining centers in Aruba and Curacao near the coast of South America.

Europe includes refineries with coastal access in Europe including the UK, France, Germany, Italy, Netherlands, Austria, Belgium, Denmark, Finland, Greece, Ireland,

Norway, Portugal, Spain, Sweden and Turkey. Two insignificant refineries in landlocked Switzerland have been included but do not influence the results of the analysis.

Latin America includes refineries in Mexico, and continental Central and South America.

Middle East includes the refineries in Abu Dhabi, Saudi Arabia, Iran, Iraq, Bahrain, Israel, Jordan, Kuwait, Oman, Qatar, Syria, and Yemen.

Far East includes the region from Pakistan to Japan and from China to New Zealand.

3.2 INTERVIEWS AND DISCUSSIONS

Discussions were held with representatives of each refiner in California producing CARB gasoline. As part of this interview process aspects of refinery operations important from a technical point of view to meeting CARB gasoline quality were identified. Further discussions were held with representatives of refiners who had historically provided imported CARB-complying gasoline as well as with representatives of other refiners and groups outside the state of California who could be reasonably expected to have insights into the possibility of fuel being provided from each region. These discussions were used to devise assessment criteria as well as cost factors that could be used to develop supply curves for CARBOB from outside the state.

3.3 CARB CAPABILITIES ASSESSMENT

Assessment criteria were developed that relate to the ability of refineries to produce CARBOB to refinery size and configuration. Variations on the assessment criteria were considered in light of the comments made by industry participants as well as a technical review of the suitability of various streams to produce CARBOB. A model was developed that scored each refinery in the world on the assessment criteria. The model is intended to provide relative capability measurement based on indicated process capability and not an absolute measure of a refinery's capability.

3.4 ALLOCATION OF REFINERIES INTO CAPABILITY CATEGORIES

Based on the results of the CARB Capabilities Assessment, each refinery in the world was allocated into one of two groups: those with a reasonable prospect of producing commercial quantities of CARB gasoline and those for which producing commercial quantities of CARB gasoline is unlikely to be practical.

3.5 KEY COMPONENT AVAILABILITY

Estimates were prepared of the total production of key CARBOB components in each region. The most critical component was identified as alkylate. Other important components include desulfurized straight run gasoline, hydrocrackate and reformate. An estimate was made of the volume of alkylate that could be made available for CARBOB production. The most intense reviews of alkylate availability were made for the Pacific

North West and USGC areas and were based on refiner comments as well as minimum requirements for other uses of alkylate.

3.6 CARBOB PRODUCTION RELATIONSHIPS

Typical gasoline blend stock characteristics for the various areas were reviewed in the context of the requirements of the predictive model. These reviews were used to estimate the relationship between the volume of potential CARBOB production and the volume of alkylate available for each region. The relationships between alkylate and CARBOB for the regions are variable based on the availabilities and qualities of the other blend stocks.

3.7 REGIONAL CARBOB CAPABILITY

An estimate was made of the volume of the gasoline produced from CARBOB-Capable refineries that could be produced as CARBOB gasoline. The volume of CARBOB was determined from the estimated volume of alkylate that could be made available and the relationship between CARBOB and alkylate for each region.

This step determines the volume of CARBOB that could be supplied from each region.

3.8 COST BASIS

A cost model was established that estimates total cost to supply CARBOB to California based on certain cost components including:

TABLE 3.8-1
CARBOB COST ELEMENTS

Local Gasoline Price
Processing Cost
Inventory Cost
Transportation Cost
Refiner Margin

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Each cost element was estimated for each region.

Local gasoline price was estimated relative to California gasoline prices based on historical relationships from the summer of 1997. This period was selected to be consistent with the price data used by Mathpro and ESAI. This element was included to reflect the market reality that refiners would be reluctant to price gasoline supplies away from local markets unless at least the locally prevailing price plus all cost elements would be provided.

Processing cost refers to costs incurred within the refinery to manufacture CARBOB instead of the local gasoline grade. These costs include the costs incurred to assign valuable blend stocks preferentially to CARBOB production rather than to regional gasoline

production and costs incurred within the refinery to make small adjustments to processing or to make product segregations. The principal elements of the processing cost are debits and credits associated with butane blending, mostly vapor pressure. A small allowance was made for other costs such as laboratory testing, more severe debutanization and other incidental costs in the refinery.

Octane credit/debit refers to the cost element associated with the difference between the prevailing octane specification in the market and the required octane for the CARBOB. Gasoline price quotations carry with them octane specifications the fuel must meet. Because CARBOB is to be blended with high octane oxygenates on delivery to California, its octane specification can be much lower than most fuels. Refiners can benefit from this factor either in producing more higher octane premium fuel for their regional markets or by reducing processing severity improving yields and reducing costs. This factor generally reduces the cost of CARBOB.

Inventory holding costs refer to costs to consolidate cargo-quantities of CARBOB. These costs include a provision for terminaling costs at the point of origin as well as time value of holding inventory during shipping. The time value of holding the inventory is limited to costs of working capital and excludes any factor related to risk management or market changes during shipping.

Transportation costs refer to the costs to provide marine transportation and destination terminaling for CARBOB from the source to California points of entry. These costs are estimated based on prevailing shipping rates based on Worldscale with appropriate adjustments for ship size and condition for international movements and typical costs reported by market participants for domestic movements.

Refiner margin is the element over and above identifiable costs to provide adequate incentive for the out of state refiner to undertake the risks and efforts necessary to produce CARBOB.

3.9 SUPPLY CURVES

Based on CARBOB volumes from each region and their cost, supply curves were developed for each relevant case.

4. REFINING CAPACITY

In this section the total refinery capacity in each region is identified and discussed. Basic information about the refineries was taken from the Oil & Gas Journal Worldwide Refinery database. There were a few modifications of this data based on information developed independently by Purvin & Gertz.

4.1 PACIFIC NORTH WEST

Table 4.1-1 shows the refineries in the Pacific North West region. There are seven refineries in the region though this total includes two that are incapable of producing any gasoline: Chevron Seattle and Sound Tacoma. Of the remaining five refineries, four are affiliates of California refiners though the Shell refinery in Anacortes is being sold pursuant to an agreement with the Federal Trade Commission.

The ARCO refinery at Cherry Point is classified as a coking refinery but the facility has a hydrocracker, not the more common Fluid Catalytic Cracker (FCC). The Texaco refinery at Anacortes is also classified as a coking refinery. The Shell and Tosco refineries are classified as cracking refineries. The U.S. Oil & Refining facility is classified as a hydroskimming refinery.

The Pacific North West region is considered generally short of petroleum products. A large volume of products carried by pipeline are delivered to Portland, Oregon from Puget Sound refiners and is supplemented by products from California, other U.S. points of origin and even foreign sources. Nevertheless, there is considerable waterborne traffic in petroleum products south to California destinations, mostly in Los Angeles. Since so much of the capacity in the Pacific North West is controlled by California refiners, opportunities exist to optimize the systems of both areas together.

4.2 U.S. GULF COAST

Table 4.2-1 shows the USGC refineries. For purposes of this report the Gulf Coast has been defined to include all of PADD III. The bulk of these refineries are located in Texas and Louisiana with a small fraction of regional capacity found in Mississippi and Alabama. A small amount of the capacity included as Gulf Coast is in inland regions of West Texas or New Mexico. The Gulf Coast region contains many large sophisticated refineries and 21 of the refineries are classified as coking refineries. Another 16 are cracking refineries and the balance are unsophisticated hydroskimming and topping refineries.

Fourteen of the Gulf Coast refineries are affiliated with California refiners. These refineries represent forty percent of all capacity on the USGC.

PADD III refineries process far more crude oil than is needed to satisfy regional demand. Products from PADD III refineries are carried by major pipeline systems into East Coast and Midwest markets, and supply some parts of the Rocky Mountains, Arizona and

northern Mexico. Inexpensive waterborne transportation allows cargoes from coastal refineries in PADD III to be shipped to foreign destinations which occurs from time to time. PADD III has been an historical supplier of occasional product shortfalls in California.

Only the Valero refinery in Corpus Christi was identified as an historical producer of CARB gasoline. Other Gulf Coast refineries are believed to have considered producing CARB gasoline in the past but not to have done so.

While the Gulf Coast refining industry is very large and has a justifiable reputation as being very sophisticated, the fraction of gasoline produced as reformulated actually is fairly limited by West Coast standards. Only about 18% of the gasoline produced in PADD III conforms to EPA reformulated fuel standards. That product is consumed in the Houston, Texas area which requires such fuels and is shipped to markets on the East Coast. Other market areas which consume large volumes of Gulf Coast products do not require reformulated gasoline.

The scale of the refining industry on the Gulf Coast, its proximity to California and historical role as an incremental California product supplier, and the large volume of alkylation capacity found on the Gulf Coast all suggest that these refineries would be logical suppliers of substantial volumes of CARBOB. The scarcity of historical CARB gasoline shipments from the Gulf Coast is thought to be primarily a cost and profitability issue rather than one of technical capability.

4.3 CARIBBEAN

Table 4.3-1 shows the Caribbean refineries. None of these is affiliated with any California refiner. Of these refineries, four are cracking refineries while the other ten are less sophisticated. Hess Oil Virgin Islands is the only historical producer of CARB reformulated gasoline in the region.

Several of the Caribbean area refineries are major product exporters. These include Hess in the Virgin Islands, Coastal in Aruba and Refineria Isla Curazao in Curacao. Of these three, Hess is the only one believed to be a regular manufacturer of U.S. reformulated gasoline. The others process heavy Venezuelan crude oils making lower quality products mostly for South American markets.

Most the refineries in the Caribbean are unlikely suppliers of CARB gasoline. The orientation of most of the refining capacity toward markets with lax specifications and historical disinterest by these refineries in supplying even EPA reformulated fuels suggests that they will not be a likely source of supply beyond the Hess refinery.

4.4 EUROPE

Table 4.4-1 shows the refineries in Europe. European refineries are a very diverse group including some very simple capacity and some extremely complex facilities. Twenty-three of the European refineries are affiliated with California refiners. These refiners represent about one quarter of all the refining capacity in Europe.

European refiners are an important source of imported refined products for the U.S. Imports originate mostly in Northwest Europe, particularly the U.K. and Rotterdam area refiners. The Neste Oy refinery in Porvoo, Finland, has produced CARB gasoline and routinely manufactures gasoline for export to the East Coast of the U.S. Finnish refinery capacity exceeds domestic requirements so the country is a regular exporter but it is a relatively low ranking source of imports for the U.S.

The growing sophistication of the European industry and the advent of some form of European Community reformulated fuels in the foreseeable future and their historical role as U.S. gasoline suppliers makes these refiners reasonable prospects for manufacturing CARBOB. Just as California refiners became more sophisticated when CARB reformulated fuels were mandated, the European refiners also are likely to become more sophisticated as European specifications are tightened. There is some prospect that marginal refiners will close their operations rather than invest for reformulated fuels and that more sophisticated refiners will expand to take their place. While the demand for the highest quality products will increase, the supply of such products also will increase as more refiners modify their operations to reduce sulfur content, benzene content and other environmentally unattractive attributes of their gasoline.

4.5 LATIN AMERICA

Table 4.5-1 shows the refineries in Latin America. The region covered by this designation includes Mexico and all of the Central and South American land mass. Island nations in the Caribbean including the islands off the coast of Venezuela, Trinidad, Curacao and Aruba, are not defined in this region and have been handled separately. The greatest concentration of Latin American capacity is in Argentina, Brazil, Mexico and Venezuela. Regional capacity is about 5.9 million barrels per day. About half the refineries in Latin America are simple topping or hydroskimming refineries. There are twenty seven cracking refineries and seven coking refineries in the region.

Five of the Latin American refineries are affiliated with California refiners. These refineries represent only about four percent of regional capacity.

Latin America has several major product exporting nations. The most important for the U.S. market is Venezuela which provides products primarily to East Coast markets. Brazil and Argentina export mostly to regional markets. Mexico, a large crude oil producer, is a net product importer and receives products from U.S. refiners mostly on the Gulf Coast.

4.6 MIDDLE EAST

Table 4.6-1 shows the 46 refineries identified in the Middle East. These refineries have a total capacity of about 5.8 million barrels per day. Most Middle East refineries have simple configurations though there are some large, relatively sophisticated refineries oriented toward product exports.

Two of the Middle East refineries, both in Saudi Arabia, are affiliated with California refiners. These two facilities have about 600,000 barrels per day of capacity, or about 11 percent of regional refinery capacity.

The Middle East has considerable export-oriented refinery capacity. These refineries are used to process local crude oils which otherwise would be exported into products prior to export.

The combination of sour crude oil qualities, relatively lax product specifications in traditional markets and poor sophistication, makes Middle East refiners as a group unlikely CARBOB suppliers. Simple configurations combined with sour crude quality indicates that most refineries are likely to have difficulty meeting CARB sulfur specifications. Most Middle East product export is naphthas, distillates and high sulfur residual fuel oil products. Gasoline is a relatively low volume export from most areas. Most of the markets served by Middle East refineries lie in Asia and East Africa. Markets which rely heavily on Middle East imports tend to use high sulfur products and at best moderate gasoline qualities.

4.7 FAR EAST

Table 4.7-1 shows the refineries in the Far East. About one third of these refineries are in China, mostly small simple facilities. Another quarter are in Japan. The balance are very widely distributed.

Far East markets are quite diverse and product quality specifications vary widely. Some refiners process exceptionally sweet crude oils reducing the likelihood of sulfur difficulties. There are many aromatics extraction plants which would be beneficial in removing objectionable aromatics and benzene from some gasoline streams. Many Far Eastern markets are now consuming unleaded gasoline though reformulated fuels programs are still in the future.

Major refining centers in Japan, Korea, Singapore and China hold the promise of supplying some CARBOB. Some of the facilities are fairly sophisticated and utilize attractive hydrocracking technology. Hydrocracking is used in many Asian refineries rather than the more common FCC technology in order to maximize distillate yields. Distillates are more important products in the Far East than they are in most other markets. A benefit of hydrocracking is that it also produces very low sulfur gasoline streams that can be useful for manufacturing CARBOB.

4.8 OTHER

There are areas of the world that are excluded from this analysis mostly because they have little prospect of supplying gasoline to California at all. These areas include Canada, central and Rocky Mountain areas of the U.S., the U.S. East Coast, the Former Soviet Union (FSU) and Central Asia, and Africa. Canada has insignificant refining capacity on the West Coast and is an impractical California supplier from other Canadian regions for

logistical reasons. The Rocky Mountain areas of the U.S. have scant refining capacity and no practical method of delivering significant volumes of gasoline to the West Coast. Likewise the central U.S. has no practical method of delivering to the West Coast. The U.S. East Coast is a major gasoline importing region and therefore is an unlikely source of fuels for California. FSU and Central Asia has little ability to produce high quality fuels of any type and certainly not CARB gasoline. Furthermore, FSU refineries are not logistically positioned to be ready fuel exporters of waterborne cargoes. Africa is an impractical supplier of products and does not generally export refined fuels of any type.

Notwithstanding that the areas discussed above were excluded from the study areas, their refinery capabilities were scanned nevertheless to identify any refineries likely to be able to manufacture CARBOB. While there are some refineries, particularly on the East Coast of the U.S., that can manufacture high quality fuels, no refineries were identified that would have a reasonable prospect of supplying CARBOB to California in these areas. On the basis of this review, the original region descriptions were reconfirmed for further analysis.

Table 4.8-1 shows the capacity of refineries in the U.S. that were excluded from the analysis. This includes all the California refineries and the other states not expected to contribute to external supplies.

Table 4.8-2 shows the capacities of refineries outside the U.S. that are not included in the supply areas. Though there is nearly 16 million barrels of capacity in these refineries, there is an aggregate of only about 50,000 barrels per day of alkylation capacity. Apart from the logistical problems that preclude most of these refineries from contributing to external CARBOB supplies, their low level of technical sophistication suggests they wouldn't be able to manufacture appreciable volumes of CARBOB.

Table 4.8-3 shows the refineries in the Other U.S. region that are affiliates of California refiners. Table 4.8-4 shows the refineries in the Other region that are affiliates of California refiners.

TABLE 4.1-1
REGIONAL REFINERY CAPACITY, PACIFIC NORTH WEST
(Barrels per Stream Day)

Company	Location	State	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
ARCO	Ferndale	WA	202,000	51,000	0	50,000	0	0	0
Shell Oil	Anacortes	WA	108,200	0	44,800	0	11,500	0	0
Sound Refining	Tacoma	WA	11,900	0	0	0	0	0	0
Texaco	Anacortes	WA	135,850	22,050	47,700	0	8,550	0	0
Tosco	Ferndale	WA	88,500	0	25,000	0	6,000	0	0
U.S. Oil & Refining	Tacoma	WA	40,800	0	0	0	0	0	0
		TOTAL	**575,350**	**73,050**	**117,500**	**50,000**	**26,050**	**0**	**0**

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TABLE 4.1-2
REGIONAL REFINERY CAPACITY, PACIFIC NORTH WEST- California Affiliates
(Barrels per Stream Day)

Company	Location	State	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
ARCO	Ferndale	WA	202,000	51,000	0	50,000	0	0	0
Chevron	Seattle	WA	0	0	0	0	0	0	0
Shell Oil [1]	Anacortes	WA	108,200	0	44,800	0	11,500	0	0
Texaco	Anacortes	WA	135,850	22,050	47,700	0	8,550	0	0
Tosco	Ferndale	WA	88,500	0	25,000	0	6,000	0	0
		Total	**534,550**	**73,050**	**117,500**	**50,000**	**26,050**	**0**	**0**

Note: Shell Anacortes is for sale pursuant to Federal Trade Commission requirements.

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TABLE 4.2-1
REGIONAL REFINERY CAPACITY, U.S. GULF COAST
(Barrels per Stream Day)

Company	Location	State	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Coastal Ref. & Mkt.	Mobile Bay	AL	15,000	0	0	0	0	0	0
Hunt Refining Co.	Tuscaloosa	AL	43,225	10,800	0	0	0	0	0
Shell Oil Products Co.	Saraland	AL	76,000	0	0	0	0	0	7,500
AIPC	Lake Charles	LA	27,600	0	0	0	0	0	0
Atlas Processing	Shreveport	LA	46,200	0	0	0	0	0	0
Basis Petroleum, Inc.	Krotz Springs	LA	67,100	0	30,700	0	0	0	0
BP Oil Co.	Belle Chasse	LA	242,250	22,500	92,700	0	34,200	21,150	0
Calcasieu Refining	Lake Charles	LA	14,000	0	0	0	0	0	0
Calumet	Princeton	LA	8,000	0	0	0	0	0	0
Calumet Lubricants Co.	Cotton Valley	LA	8,740	0	0	0	0	0	0
Canal Refining Co.	Church Point	LA	9,000	0	0	0	0	0	0
CITGO	Lake Charles	LA	304,000	84,600	117,000	36,000	20,700	4,500	0
Conoco	Lake Charles/Westlake	LA	226,000	65,000	50,000	26,600	10,400	0	0
Exxon	Baton Rouge	LA	432,000	99,000	204,000	22,500	35,000	0	0
Marathon Oil	Garyville	LA	225,000	0	90,000	0	26,000	0	0
Mobil Oil	Chalmette	LA	176,400	33,300	62,000	20,000	12,000	9,600	0
Murphy Oil	Meraux	LA	95,000	0	36,000	0	8,000	0	0
Placid Refining	Port Allen	LA	48,000	0	19,000	0	3,800	0	0
Shell Chemical Co.	St. Rose	LA	40,000	0	0	0	0	0	0
Shell Oil	Norco	LA	218,000	24,500	108,000	35,000	15,000	0	0
Star Enterprise	Convent	LA	230,000	0	82,500	45,000	13,050	0	0
Chevron	Pascagoula	MS	295,000	71,000	63,000	58,000	14,800	15,100	0
Ergon Refining	Vicksburg	MS	25,000	0	0	0	0	0	0
Southland Oil	Lumberton	MS	5,800	0	0	0	0	0	0
Southland Oil	Sandersville	MS	11,000	0	0	0	0	0	0
Giant Industries	Gallup	NM	20,800	0	8,500	0	1,800	0	0
Giant Refining Co.	Bloomfield	NM	16,800	0	5,331	0	0	0	0
Navajo Refining	Artesia	NM	60,000	0	18,500	0	9,400	0	0

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TABLE 4.2-1 (CONTINUED)
REGIONAL REFINERY CAPACITY, U.S. GULF COAST
(Barrels per Stream Day)

Company	Location	State	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
AGE Refining & Manufacturing	San Antonio	TX	5,000	0	0	0	0	0	0
Amoco Oil	Texas City	TX	433,000	34,200	196,700	114,000	58,900	42,800	0
Basis Petroleum, Inc.	Houston	TX	67,600	0	58,500	0	10,400	5,700	0
Basis Petroleum, Inc.	Texas City	TX	125,400	0	48,000	0	5,700	0	0
Chevron	El Paso	TX	90,000	2,400	28,000	0	8,200	0	0
CITGO	Corpus Christi	TX	130,000	36,000	77,000	0	21,000	*0*	0
Clark	Port Arthur	TX	185,000	33,000	63,000	0	15,500	9,800	0
Coastal Ref. & Mkt.	Corpus Christi	TX	95,000	12,000	20,000	18,500	3,200	17,500	0
Crown Central	Houston	TX	100,000	11,250	50,400	0	11,700	0	0
Deer Park Refining	Deer Park	TX	255,700	61,300	64,900	62,600	16,500	17,900	0
Diamond Shamrock	Sunray/McKee	TX	135,000	0	45,000	25,000	8,700	0	0
Diamond Shamrock	Three Rivers	TX	80,000	0	20,000	25,000	6,000	0	0
Exxon	Baytown	TX	411,000	31,000	190,000	24,000	28,000	0	0
Fina Oil & Chemical	Big Spring	TX	58,000	0	22,500	0	5,000	1,000	0
Fina Oil & Chemical	Port Arthur	TX	178,500	0	61,000	0	5,500	13,000	0
Howell Hydrocarbons	Channelview	TX	2,400	0	0	0	0	0	0
Koch Refining	Corpus Christi	TX	280,000	15,000	92,000	15,000	20,000	36,000	0
LaGloria Oil & Gas	Tyler	TX	52,000	5,400	16,500	0	4,200	0	0
Lyondell-CITGO	Houston	TX	258,000	42,000	92,000	0	20,900	13,700	0
Marathon Oil	Texas City	TX	70,000	0	32,000	0	10,000	2,500	0
Mobil Oil	Beaumont	TX	320,000	45,500	100,000	50,000	12,200	0	14,400
NTPS	Corpus Christi	TX	30,000	0	0	0	0	0	0
Phillips 66 Co.	Borger	TX	120,000	0	57,000	0	17,500	0	13,500
Phillips 66 Co.	Sweeny	TX	200,000	0	91,600	0	19,000	5,300	9,000
Pride Refining	Abilene	TX	44,800	0	0	0	0	0	0
Shell Oil	Odessa	TX	28,300	0	9,600	0	3,200	0	0
Star Enterprise	Port Arthur	TX	235,000	49,500	83,000	17,820	18,000	0	0
Valero Refining Co.	Corpus Christi	TX	29,900	0	64,000	30,000	10,800	0	0
		TOTAL	**7,005,515**	**789,250**	**2,569,931**	**625,020**	**544,250**	**215,550**	**44,400**

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TABLE 4.2-2
REGIONAL REFINERY CAPACITY, U.S. GULF COAST- California Affiliates
(Barrels per Stream Day)

Company	Location	State	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Shell Oil Products Co.	Saraland	AL	76,000	0	0	0	0	0	7,500
Exxon	Baton Rouge	LA	432,000	99,000	204,000	22,500	35,000	0	0
Mobil Oil	Chalmette	LA	176,400	33,300	62,000	20,000	12,000	9,600	0
Shell Chemical Co.	St. Rose	LA	40,000	0	0	0	0	0	0
Shell Oil	Norco	LA	218,000	24,500	108,000	35,000	15,000	0	0
Star Enterprise	Convent	LA	230,000	0	82,500	45,000	13,050	0	0
Chevron	Pascagoula	MS	295,000	71,000	63,000	58,000	14,800	15,100	0
Chevron	El Paso	TX	90,000	2,400	28,000	0	8,200	0	0
Diamond Shamrock	Sunray/McKee	TX	135,000	0	45,000	25,000	8,700	0	0
Diamond Shamrock	Three Rivers	TX	80,000	0	20,000	25,000	6,000	0	0
Exxon	Baytown	TX	411,000	31,000	190,000	24,000	28,000	0	0
Mobil Oil	Beaumont	TX	320,000	45,500	100,000	50,000	12,200	0	14,400
Shell Oil	Odessa	TX	28,300	0	9,600	0	3,200	0	0
Star Enterprise	Port Arthur	TX	235,000	49,500	83,000	17,820	18,000	0	0
		Total	**2,793,700**	**356,200**	**995,100**	**322,320**	**174,150**	**24,700**	**21,900**

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TABLE 4.3-1
REGIONAL REFINERY CAPACITY, CARIBBEAN
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Aruba	Coastal Aruba Refining Co. N.V.	San Nicolas	210,000	27,900	0	38,000	0	0	0
Barbados	Mobil Oil Barbados Ltd.	Bridgetown	6,000	0	0	0	0	0	0
Cuba	Government	Nico Lopez, Havana	121,800	0	14,700	0	0	0	0
Cuba	Government	Cabaiguan	2,100	0	0	0	0	0	0
Cuba	Government	Santiago de Cuba	101,500	0	0	0	0	0	0
Cuba	Government	Cienfuegos	76,000	0	0	0	0	0	0
Dominican Republic	Falconbridge Dominicana C por A	La Bonao	16,000	0	0	0	0	0	0
Dominican Republic	Refineria Dominicana de Petroleo SA	Haina	34,000	0	0	0	0	0	0
Jamaica	Petrojam Ltd.	Kingston	35,500	0	0	0	0	0	0
Martinique	Ste. Anonyme de la Raffinerie des Antilles	Fort-de-France	16,000	0	0	0	0	0	0
Netherlands Antilles	Refineria Isla Curazao SA	Emmastad	320,000	0	49,000	0	8,020	0	0
Puerto Rico	Puerto Rico Sun Oil Co.	Yabucoa	85,000	0	0	15,600	0	0	0
Trinidad	Trinidad and Tobago Oil CL	Pointe-a-Pierre	165,000	0	25,000	0	1,200	1,700	0
Virgin Islands	Hess Oil Virgin Islands Corp.	St. Croix	545,000	0	125,000	0	14,000	30,000	15,000
		TOTAL	**1,733,900**	**27,900**	**213,700**	**53,600**	**23,220**	**31,700**	**15,000**

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TABLE 4.3-2
REGIONAL REFINERY CAPACITY, CARIBBEAN- California Affiliates
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
No California Affiliates in the Caribbean Region									

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TABLE 4.4-1
REGIONAL REFINERY CAPACITY, EUROPE
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Austria	OeMV	Schwechat	210,000	0	25,800	0	0	0	0
Belgium	Belgian Refining Corp. NV	Antwerp	80,750	0	0	0	0	0	0
Belgium	Esso Belgium	Antwerp	246,000	0	33,300	0	6,815	0	0
Belgium	Fina Raffinaderij Antwerpen-	Antwerp	288,000	0	77,600	0	6,700	0	0
Belgium	Nynas Petroleum NV	Antwerp	15,000	0	0	0	0	0	0
Denmark	AS Dansk Shell	Fredericia	66,700	0	0	0	0	0	0
Denmark	Dansk Statoil AS	Kalundborg	88,000	0	0	0	0	0	0
Denmark	Kuwait Petroleum Refining	Gulfhavn (Skaelskoer)	57,400	0	0	0	0	0	0
Finland	Neste Oy	Porvoo	200,000	0	31,000	16,000	4,200	0	3,600
Finland	Neste Oy	Naantali	40,000	0	14,200	0	0	0	0
France	Total France	La Mede	127,000	0	30,000	0	3,000	0	0
France	Total France	Gonfreville L'Orcher	333,000	0	41,000	0	0	0	0
France	Total France	Mardyck	127,000	0	32,000	0	0	0	0
France	Cie. Rhenane de Raffinage	Reichstett-Vendenheim	82,000	0	14,000	0	0	0	0
France	Elf France	Donges	214,300	0	49,400	0	4,300	0	0
France	Elf France	Feyzin	128,130	0	24,940	0	3,500	2,200	0
France	Elf France	Grandpuits	98,000	0	30,720	0	3,150	0	0
France	Esso SAF	Port Jerome	156,000	0	29,500	0	5,900	0	0
France	Esso SAF	Fos sur Mer	117,000	0	25,000	0	0	0	0
France	Mobil Oil Francaise	Notre Dame de Gravenchon	63,650	0	0	0	0	0	0
France	Shell Francaise	Berre l'Etang	127,000	0	34,000	0	0	0	0
France	Shell Francaise	Petit Couronne	141,000	0	20,000	0	0	0	0
France	Ste. Francaise des Petroles BP	Lavera	199,500	0	27,900	15,300	0	6,600	0

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TABLE 4.4-1 (CONTINUED)
REGIONAL REFINERY CAPACITY, EUROPE
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Germany	BETA	Wihelmshaven	180,000	0	0	0	0	0	0
Germany	BP/AGIP	Vohburg/Ingolstadt	114,000	0	35,100	0	0	0	0
Germany	DEA Mineraloel AG	Wesseling	120,000	0	0	40,000	0	7,600	0
Germany	DEA Mineraloel AG	Heide	98,000	0	9,000	0	0	5,800	0
Germany	Deutsche Shell AG	Godorf	170,000	0	0	36,000	0	17,000	0
Germany	Deutsche Shell AG	Harburg-Grasbrook	98,000	0	16,000	0	0	0	0
Germany	Erdoel Raffinerie Neustadt GmbH	Neustadt-Donau	144,000	0	23,400	0	0	0	0
Germany	Esso AG	Ingolstadt	105,000	0	27,500	0	0	0	0
Germany	Holburn Europa Raffinerie GmbH	Harburg	78,000	0	18,750	0	0	0	0
Germany	Leune-Werke AG	Leuna	100,000	0	0	40,000	6,000	0	0
Germany	Mineraloel Oberrhein	Karlsruhe	325,800	21,000	74,000	0	10,200	0	0
Germany	OMV Mineralol Petrochemie	Burghausen	72,000	27,500	0	0	0	2,300	0
Germany	PCK Schwedt AG	Schwedt	230,000	0	51,000	0	6,100	5,000	0
Germany	Ruhr Oel GmbH	Gelsenkirchen	227,000	28,000	21,000	30,000	0	*3,650*	0
Germany	Schmierstoff Raffinerie	Salzbergen	3,100	0	0	0	0	0	0
Germany	Wintershall AG	Lingen	80,000	18,000	0	23,000	0	4,674	0
Greece	Hellenic Aspropyrgos Refinery SA	Aspropyrgos	121,000	0	36,000	0	0	0	0
Greece	Motor Oil (Hellas)	Aghii Theodori	100,000	0	30,400	0	2,400	0	5,200
Greece	Petrola Hellas SA	Elefsis	108,000	0	0	0	0	0	0
Greece	Thessaloniki Refining Co. AE	Thessaloniki	66,500	0	0	0	0	0	0
Ireland	Irish Refining Petroleum Corp. Ltd.	Whitegate	65,000	0	0	0	0	0	0

TABLE 4.4-1 (CONTINUED)
REGIONAL REFINERY CAPACITY, EUROPE
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Italy	Agip Plus SpA	Livorno	84,000	0	0	0	0	0	0
Italy	Agip Raffinazione	Sannazzaro, Pavia	200,000	0	34,000	30,000	3,200	0	0
Italy	Agip Raffinazione	Taranto	84,000	0	0	16,000	0	0	0
Italy	Agip Raffinazione	Porto Marghera	80,000	0	0	0	0	0	0
Italy	Anonima Petroli Italiana	Falconara, Marittima	77,000	0	0	0	0	0	0
Italy	Arcola Petrolifera SpA	La Spezia	33,000	0	0	0	0	0	0
Italy	ENI	Priolo	220,000	0	32,000	0	4,000	12,000	0
Italy	Esso Italiana SpA	Augusta, Siracusa	182,500	0	43,200	0	7,900	0	0
Italy	Iplom SpA	Busalla	46,500	0	0	0	0	0	0
Italy	Isab	Priolo Gargallo Melilli	235,000	0	0	65,000	0	0	0
Italy	Italiana Energia E Servizi SpA	Frassino, Mantova	50,318	0	0	0	0	0	0
Italy	Raffineria di Roma SpA	Rome	81,500	0	0	0	0	0	0
Italy	Raffineria Mediterranea SrL	Milazzo	160,000	0	49,000	50,000	5,000	0	0
Italy	Raffineria Siciliana Srl	Gela	105,000	45,000	35,000	0	10,000	6,700	0
Italy	Saras SpA	Sarroch	285,000	0	80,000	50,000	6,800	0	0
Italy	Sarpom	S. Martino Di Trecate	248,000	0	25,200	0	0	0	0
Italy	Tamoil Italia SpA	Cremona	90,000	0	0	0	0	0	0
Netherlands	Esso Nederland BV	Rotterdam	180,000	36,660	0	33,850	0	12,000	0
Netherlands	Kuwait Petroleum Europoort BV	Rotterdam	75,500	0	0	0	0	0	0
Netherlands	Netherlands Refining Co. NV	Europort & Pernis	399,000	0	53,000	0	5,850	0	0
Netherlands	Shell Nederland Raffinaderij BV	Pernis	374,000	0	87,000	22,000	6,800	0	0
Netherlands	Smid & Hollander Raffinaderij BV	Amsterdam	10,000	0	0	0	0	0	0
Netherlands	Total Raffinaderij Nederland NV	Vlissingen	148,000	0	0	39,000	0	0	0

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TABLE 4.4-1 (CONTINUED)
REGIONAL REFINERY CAPACITY, EUROPE
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Norway	Esso Norge AS	Slagen-Valloy	100,000	0	0	0	0	0	0
Norway	Norske Shell AS	Sola	53,000	0	0	0	0	0	0
Norway	Rafinor AS	Mongstad	154,000	25,000	48,000	0	0	0	0
Portugal	Petrogal	Sines	212,895	0	31,500	0	5,400	0	0
Portugal	Petrogal	Leca da Palmeira Porto	91,277	0	0	0	0	6,282	0
Spain	Asfaltos Espanoles SA	Tarragona	21,000	0	0	0	0	0	0
Spain	Cia. Espanola de Petroles	San Roque (Cadiz)	205,000	0	40,000	0	5,000	13,100	10,000
Spain	Cia. Espanola de Petroles	La Rabida Huelva	100,000	0	18,000	0	0	2,420	0
Spain	Cia. Espanola de Petroles	Tenerife	89,000	0	0	0	0	0	0
Spain	Petroleos del Mediterraneo	Castellon de la Plana	101,650	0	22,500	0	0	0	0
Spain	Petronor SA	Somorrostro Vizcaya	209,000	0	39,600	0	4,496	0	0
Spain	Repsol Petroleo SA	Puertollano, Ciudad Real	135,000	16,000	30,000	0	3,300	1,800	0
Spain	Repsol Petroleo SA	Tarragona	180,000	0	0	15,000	0	0	0
Spain	Repsol Petroleo SA	La Coruna	135,000	13,500	28,000	0	0	0	0
Spain	Repsol Petroleo SA	Cartagena Murcia	120,000	0	0	0	0	0	0
Sweden	AB Nynas Petroleum	Gothenburg	12,500	0	0	0	0	0	0
Sweden	AB Nynas Petroleum	Nynashamn	28,000	0	0	0	0	0	0
Sweden	OK Petroleum	Gothenburg	106,000	0	0	0	0	0	0
Sweden	Shell Raffinaderi BV	Gothenburg	81,000	0	0	0	0	0	0
Sweden	Skandinaviska Raffinaderi AB	Brofjorden-Lysekil	200,000	0	29,700	48,600	0	0	0
Switzerland	Raffinerie de Cressier SA	Cressier	60,000	0	0	0	0	0	0
Switzerland	Raffinerie du Sud-Ouest SA	Collombey	72,000	0	0	0	0	0	0

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TABLE 4.4-1 (CONTINUED)
REGIONAL REFINERY CAPACITY, EUROPE
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Turkey	Anadolu Tasfiyehanesi AS	Mersin	95,000	0	0	0	0	5,800	0
Turkey	Turkish Petroleum Refineries Corp.	Izmit	251,600	0	22,645	23,000	0	0	0
Turkey	Turkish Petroleum Refineries Corp.	Aliaga-Izmir	226,440	0	15,095	16,500	0	0	0
Turkey	Turkish Petroleum Refineries Corp.	Kirkkale	113,220	0	0	14,500	0	0	0
Turkey	Turkish Petroleum Refineries Corp.	Batman, Siirt	22,015	0	0	0	0	0	0
United Kingdom	BP Refinery Grangemouth Ltd.	Grangemouth	194,750	0	18,900	31,500	4,500	1,000	0
United Kingdom	Conoco Ltd.	South Killingholme	180,000	70,000	50,000	0	14,000	4,500	0
United Kingdom	Eastham Refinery Ltd.	Eastham, Cheshire	22,000	0	0	0	0	0	0
United Kingdom	Elf Oil Ltd.	Milford Haven	108,000	0	32,500	0	6,400	0	0
United Kingdom	Esso Petroleum CL	Fawley	317,000	0	85,000	0	0	0	0
United Kingdom	Gulf Oil GB	Milford Haven	112,000	0	0	0	0	0	0
United Kingdom	Lindsey Oil Refinery Ltd.	Killingholm South Humberside	192,000	0	48,400	0	6,300	0	0
United Kingdom	Mobil Oil CL	Coryton Essex	171,000	0	56,250	0	18,000	0	0
United Kingdom	Nynas	Dundee	10,240	0	0	0	0	0	0
United Kingdom	Pembroke Cracking Co. (1)	Milford Haven	0	0	90,000	0	33,000	0	0
United Kingdom	Phillips Imperial Petroleum Ltd.	Port Clarence	100,000	0	0	0	0	0	0
United Kingdom	Shell U.K. Ltd.	Stanlow	262,000	0	73,000	0	11,000	9,000	0
United Kingdom	Shell U.K. Ltd.	Shell Haven	92,000	0	0	24,000	0	0	0
United Kingdom	Texaco Ltd.	Pembroke, Dyfed	180,000	0	0	0	0	0	0
		TOTAL	**14,374,735**	**300,660**	**2,100,000**	**679,250**	**223,211**	**129,426**	**18,800**

Note: (1) 65% Texaco 35% Gulf Oil GB.

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TABLE 4.4-2
REGIONAL REFINERY CAPACITY, EUROPE- California Affiliates
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Belgium	Esso Belgium	Antwerp	246,000	0	33,300	0	6,815	0	0
Denmark	AS Dansk Shell	Fredericia	66,700	0	0	0	0	0	0
France	Esso SAF	Port Jerome	156,000	0	29,500	0	5,900	0	0
France	Esso SAF	Fos sur Mer	117,000	0	25,000	0	0	0	0
France	Mobil Oil Francaise	Notre Dame de Gravenchon	63,650	0	0	0	0	0	0
France	Shell Francaise	Berre l'Etang	127,000	0	34,000	0	0	0	0
France	Shell Francaise	Petit Couronne	141,000	0	20,000	0	0	0	0
Germany	Esso AG	Karlsruhe	0	0	0	0	0	0	0
Germany	Esso AG	Ingolstadt	105,000	0	27,500	0	0	0	0
Germany	Mobil Oil AG	Woerth	0	0	0	0	0	0	0
Italy	Esso Italiana SpA	Augusta, Siracusa	182,500	0	43,200	0	7,900	0	0
Netherlands	Esso Nederland BV	Rotterdam	180,000	36,660	0	33,850	0	12,000	0
Netherlands	Shell Nederland Raffinaderij BV	Pernis	374,000	0	87,000	22,000	6,800	0	0
Netherlands	Texaco	Pernis	0	0	0	0	0	0	0
Norway	Esso Norge AS	Slagen-Valloy	100,000	0	0	0	0	0	0
Norway	Norske Shell AS	Sola	53,000	0	0	0	0	0	0
Sweden	Shell Raffinaderi BV	Gothenburg	81,000	0	0	0	0	0	0
Sweden	Skandinaviska Raffinaderi AB	Brofjorden-Lysekil	200,000	0	29,700	48,600	0	0	0
United Kingdom	Esso Petroleum CL	Fawley	317,000	0	85,000	0	0	0	0
United Kingdom	Mobil Oil CL	Coryton Essex	171,000	0	56,250	0	18,000	0	0
United Kingdom	Shell U.K. Ltd.	Stanlow	262,000	0	73,000	0	11,000	9,000	0
United Kingdom	Shell U.K. Ltd.	Shell Haven	92,000	0	0	24,000	0	0	0
United Kingdom	Texaco Ltd.	Pembroke, Dyfed	180,000	0	0	0	0	0	0
		Total	**3,214,850**	**36,660**	**543,450**	**128,450**	**56,415**	**21,000**	**0**

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TABLE 4.5-1
REGIONAL REFINERY CAPACITY, LATIN AMERICA
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-Cracking	Alkylation	Aromatics	Isom
Argentina	Destileria Argentina	Lomas de Zamora	8,000	0	0	0	0	0	0
Argentina	Esso SAPA	Campana	88,100	25,000	27,300	0	0	0	0
Argentina	Esso SAPA	Puerto Galvan	19,000	0	0	0	0	0	0
Argentina	Isaura SA	Bahia Blanca	28,980	0	7,076	0	0	0	0
Argentina	Shell Cia. Argentina	Dock Sud	121,700	0	29,200	0	1,700	0	0
Argentina	Sol Petroleo SA	San Francisco Solana, Quillmes	6,000	0	0	0	0	0	0
Argentina	YPF	Lujan de Cuyo	120,000	35,200	44,700	26,000	0	0	0
Argentina	YPF	La Plata	176,000	39,000	73,600	0	0	0	0
Argentina	YPF	Plaza Huincul	23,600	0	0	0	0	0	0
Argentina	YPF	Campo Duran	32,000	0	0	0	0	0	0
Argentina	YPF	Dock Sud	4,000	0	0	0	0	0	0
Argentina	YPF	San Lorenzo	37,600	0	0	0	0	0	0
Bolivia	YPFB	Cochabamba	25,888	0	0	0	0	0	0
Bolivia	YPFB	Santa Cruz	19,000	0	0	0	0	0	0
Bolivia	YPFB	Sucre	3,000	0	0	0	0	0	0
Brazil	REFAP	Canoas, Rio Grande do Sul	68,230	0	14,040	0	0	0	0
Brazil	REFCAP	Maua Santo Andre, Sao Paulo	38,100	0	11,580	0	0	0	0
Brazil	DRGP	Rio Grande do Sul	12,500	0	3,000	0	0	0	0
Brazil	REDUC	Duque de Caxias, Rio de Janeiro	225,730	15,720	41,360	0	0	0	0
Brazil	REGAP	Betim, Minas Gerais	136,470	0	33,080	0	0	0	0
Brazil	REVAP	Sao Jose dos Campos, Sao Paulo	204,700	0	57,900	0	0	0	0
Brazil	RLAM	Mataripe, Bahia	117,960	0	24,810	0	0	0	0
Brazil	REMAN	Manaus, Amazonas	10,230	0	2,200	0	0	0	0
Brazil	REPLAN	Paulinia, Sao Paulo	272,930	0	50,314	0	0	0	0
Brazil	RPBC	Cubatao, Sao Paulo	155,325	32,700	49,620	0	3,140	7,550	0
Brazil	REPAR	Araucaria, Parana	159,210	0	45,700	0	0	0	0
Brazil	RPM	Rio de Janeiro	10,000	0	0	0	0	0	0

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TABLE 4.5-1 (CONTINUED)
REGIONAL REFINERY CAPACITY, LATIN AMERICA
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-Cracking	Alkylation	Aromatics	Isom
Chile	ENAP	Gregorio-Magallanes	9,650	0	0	0	0	0	0
Chile	Petrox SA	Talcahuano	100,640	0	20,757	0	0	0	0
Chile	Refineria de Concon	Concon	82,000	0	25,000	12,580	1,100	0	0
Colombia	ECO Petrol	Barrancabermeja-Santander	173,000	0	64,000	0	2,100	1,600	0
Colombia	ECO Petrol	Cartagena, Bolivar	70,000	0	26,000	0	0	0	0
Colombia	ECO Petrol	Orito, Putumayo	1,800	0	0	0	0	0	0
Colombia	ECO Petrol	Tibu, N. de Santander	1,800	0	0	0	0	0	0
Colombia	ECO Petrol	Apiay	2,250	0	0	0	0	0	0
Costa Rica	Refinadora Costarricense	Limon	15,000	0	0	0	0	0	0
Ecuador	Petroecuador	Esmeraldas	90,000	0	0	0	0	*0*	0
Ecuador	Petroecuador	Sta. Elena Peninsula	47,000	0	0	0	0	0	0
Ecuador	Petroecuador	Refineria Amazonas	20,000	0	0	0	0	0	0
Ecuador	Petroecuador	Lago-Agrio	1,000	0	0	0	0	0	0
El Salvador	Refineria Petrolera Acajutla	Acajutla	20,500	0	0	0	0	0	0
Guatemala	Basic Resources International	Peten	4,000	0	0	0	0	0	0
Guatemala	Texas Petroleum Co.	Escuintla	16,000	0	0	0	0	0	0
Honduras	Refineria Texas de Honduras	Puerto Cortes	14,000	0	0	0	0	0	0
Mexico	Pemex	Ciudad Madero	195,000	10,000	43,000	0	3,420	0	0
Mexico	Pemex	Salamanca	240,000	0	60,000	18,500	0	0	0
Mexico	Pemex	Minatitlan	200,000	0	40,000	0	0	17,150	0
Mexico	Pemex	Cadereyta	235,000	0	40,000	0	0	0	0
Mexico	Pemex	Salina Cruz	330,000	0	80,000	0	14,100	0	0
Mexico	Pemex	Tula Hidalgo	320,000	0	80,000	0	0	0	0

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TABLE 4.5-1 (CONTINUED)
REGIONAL REFINERY CAPACITY, LATIN AMERICA
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-Cracking	Alkylation	Aromatics	Isom
Nicaragua	Esso Standard Oil SA Ltd.	Managua	16,500	0	0	0	0	0	0
Panama	Refineria Panama SA	Las Minas	60,000	0	0	0	0	0	0
Paraguay	Petroleos Paraguayos	Villa Elisa	7,500	0	0	0	0	0	0
Peru	Maples Gas	Pucallpa	3,250	0	0	0	0	0	0
Peru	Petroleos del Peru	La Pampilla Lima	100,000	0	6,700	0	0	0	0
Peru	Petroleos del Peru	Marsella Loreto	0	0	0	0	0	0	0
Peru	Petroleos del Peru	Conchan/Lima	6,500	0	0	0	0	0	0
Peru	ANC	Talara	62,000	0	16,600	0	0	0	0
Peru	Petroleos del Peru	Iquitos Loreto	10,500	0	0	0	0	0	0
Uruguay	ANC	La Teja Montevideo	40,000	0	9,000	0	0	0	0
Venezuela	Corpoven	El Palito Carabobo	115,000	0	52,000	0	20,000	3,500	0
Venezuela	Corpoven	Puerto La Cruz Anzoategui	195,000	0	13,000	0	4,100	0	0
Venezuela	Corpoven	El Toreno Barinas	4,800	0	0	0	0	0	0
Venezuela	Corpoven	San Roque, Anzoategui	5,200	0	0	0	0	0	0
Venezuela	Lagoven	Judibana Falcon	571,000	52,100	97,200	0	17,800	0	0
Venezuela	Maraven	Punta Cardon Falcon	286,000	0	72,700	0	28,800	0	0
		TOTAL	**5,796,143**	**209,720**	**1,261,437**	**57,080**	**96,260**	**29,800**	**0**

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TABLE 4.5-2
REGIONAL REFINERY CAPACITY, LATIN AMERICA- California Affiliates
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-Cracking	Alkylation	Aromatics	Isom
Argentina	Esso SAPA	Campana	88,100	25,000	27,300	0	0	0	0
Argentina	Esso SAPA	Puerto Galvan	19,000	0	0	0	0	0	0
Argentina	Shell Cia. Argentina de Petroleo SA	Dock Sud	121,700	0	29,200	0	1,700	0	0
Barbados	Mobil Oil Barbados Ltd.	Bridgetown	6,000	0	0	0	0	0	0
Guatemala	Texas Petroleum Co.	Escuintla	16,000	0	0	0	0	0	0
Honduras	Refineria Texas de Honduras	Puerto Cortes	14,000	0	0	0	0	0	0
Nicaragua	Esso Standard Oil SA Ltd.	Managua	16,500	0	0	0	0	0	0
Panama	Refineria Panama SA	Las Minas	60,000	0	0	0	0	0	0
		Total	**341,300**	**25,000**	**56,500**	**0**	**1,700**	**0**	**0**

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TABLE 4.6-1
REGIONAL REFINERY CAPACITY, MIDDLE EAST
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Abu Dhabi	ADNOC	Ruwais	132,050	0	0	26,730	0	0	0
Abu Dhabi	ADNOC	Umm Al-Nar	80,750	0	0	0	0	0	0
Bahrain	Bahrain Petroleum Co.	Awali	248,900	0	41,400	48,600	3,060	0	0
Cyprus	Cyprus Petroleum Refinery Ltd	Larnaca	26,000	0	0	0	0	0	0
Fujairah	Metro Oil Corporation	Fujairah	35,000	0	0	0	0	0	0
Iran	NIOC	Tehran	225,000	0	0	57,200	0	0	0
Iran	NIOC	Isfahan	265,000	0	0	30,000	0	0	0
Iran	NIOC	Arak	150,000	0	0	24,500	0	0	0
Iran	NIOC	Tabriz	112,000	0	0	18,000	0	0	0
Iran	NIOC	Shiraz	40,000	0	0	9,280	0	0	0
Iran	NIOC	Abadan	400,000	0	30,000	0	0	0	0
Iran	NIOC	Lavan	20,000	0	0	0	0	0	0
Iran	NIOC	Kermanshah (Bakhtaran)	30,000	0	0	0	0	0	0
Iraq	Ministry of Oil	Baiji, North	150,000	0	0	38,000	0	4,000	0
Iraq	Ministry of Oil	Dorah	92,000	0	0	0	0	0	0
Iraq	Ministry of Oil	Basrah	126,000	0	0	0	0	0	0
Iraq	Ministry of Oil	Haditha	7,000	0	0	0	0	0	0
Iraq	Ministry of Oil	Khanaqin	12,000	0	0	0	0	0	0
Iraq	Ministry of Oil	Nassiriyah	27,000	0	0	0	0	0	0
Iraq	Ministry of Oil	Qayyarah	12,500	0	0	0	0	0	0
Iraq	Ministry of Oil	Kirkuk	27,000	0	0	0	0	0	0
Iraq	Ministry of Oil	Baiji, Sulahuddin	140,000	0	0	0	0	0	0
Iraq	Ministry of Oil	Al Jezira	20,000	0	0	0	0	0	0
Iraq	Ministry of Oil	Al Syniya	20,000	0	0	0	0	0	0
Iraq	Ministry of Oil	Kasek	20,000	0	0	0	0	0	0
Israel	Oil Refineries	Haifa	130,000	0	22,000	0	0	5,000	0
Israel	Oil Refineries	Ashdod	90,000	0	27,500	0	0	0	0

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TABLE 4.6-1 (CONTINUED)
REGIONAL REFINERY CAPACITY, MIDDLE EAST
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro cracking	Alkylation	Aromatics	Isom
Jordan	Jordan Petroleum Refinery	Zarqa	100,000	0	4,350	4,230	0	0	0
Kuwait	KNPC	Shuaiba	154,000	0	0	82,000	0	0	0
Kuwait	KNPC	Mina Abdulla	255,000	60,000	0	38,000	0	0	0
Kuwait	KNPC	Mina Al-Ahmadi	415,000	0	28,000	36,000	0	0	0
Neutral Zone	Arabian Oil CL	Al Khafji	30,000	0	0	0	0	0	0
Oman	Oman Refinery Co.	Mina Al Fahal	85,000	0	0	0	0	0	0
Qatar	QGPC	Umm Saeed	57,500	0	0	0	0	0	0
Saudi Arabia	Arabian Oil Co. Ltd.	Ras Al Khafji	30,000	0	0	0	0	0	0
Saudi Arabia	Jeddah Refining Company	Jeddah	82,000	0	13,000	10,000	0	0	0
Saudi Arabia	Saudi Aramco	Riyadh	140,000	0	0	33,820	0	*0*	0
Saudi Arabia	Saudi Aramco	Ras Tanura	300,000	0	0	0	0	0	0
Saudi Arabia	Saudi Aramco	Yanbu	190,000	0	0	0	0	0	0
Saudi Arabia	Saudi Aramco	Rabigh	290,000	0	0	0	0	0	0
Saudi Arabia	Saudi Aramco-Mobil	Yanbu	331,700	0	90,600	40,000	23,500	0	0
Saudi Arabia	Saudi Aramco-Shell	Jubail	292,000	0	0	44,000	0	5,800	0
Syria	Banias Refining Co.	Banias	135,000	0	0	25,000	0	0	0
Syria	Homs Refinery Co.	Homs	110,890	20,150	0	0	0	0	525
Yemen	Aden Refinery Co.	Aden	110,000	0	0	0	0	0	0
Yemen	Ministry of Oil	Marib	10,000	0	0	0	0	0	0
		Total	**5,756,290**	**80,150**	**256,850**	**565,360**	**26,560**	**14,800**	**525**

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TABLE 4.6-2
REGIONAL REFINERY CAPACITY, MIDDLE EAST- California Affiliates
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Saudi Arabia	Saudi Aramco-Mobil	Yanbu	331,700	0	90,600	0	23,500	0	0
Saudi Arabia	Saudi Aramco-Shell	Jubail	292,000	0	0	44,000	0	5,800	0
		Total	**623,700**	**0**	**90,600**	**44,000**	**23,500**	**5,800**	**0**

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TABLE 4.7-1
REGIONAL REFINERY CAPACITY, FAR EAST
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Australia	Ampol	Kurnell	109,250	0	46,000	0	7,800	0	0
Australia	Ampol	Lytton	95,000	0	32,000	0	3,300	0	0
Australia	Australian Lubricating Oil Refinery Ltd.	Kurnell	0	0	0	0	0	0	0
Australia	BP Australia	Bulwer Island	69,350	0	18,000	0	1,890	0	0
Australia	BP Australia	Kwinana	131,575	0	27,900	0	2,430	0	0
Australia	Inland Oil Refiners	Eromanga	1,500	0	0	0	0	0	0
Australia	Mobil Oil Australia Ltd.	Adelaide (Port Stanvac)	68,400	0	0	0	0	0	0
Australia	Mobil Oil Australia Ltd.	Altona	102,600	0	23,000	0	2,500	0	0
Australia	Shell Refining (Australia) PL	Clyde	81,700	0	35,000	0	3,000	0	0
Australia	Shell Refining (Australia) PL	Geelong	104,500	0	38,000	0	4,500	0	0
Bangladesh	Eastern Refinery Ltd.	Chittagong	31,200	0	0	1,180	0	0	0
Brunei	Brunei Shell Petroleum CL	Seria	8,600	0	0	0	0	0	0
Burma	Myanmar Petrochemical Enterprise	Chauk	6,000	0	0	0	0	0	0
Burma	Myanmar Petrochemical Enterprise	Thanlyin (Mann)	26,000	5,200	0	0	0	0	0
China	Anqing Petrochemical	Anqing	60,247	8,000	24,000	0	1,000	0	0
China	Anshan Petrochemical	Anshan	50,205	0	24,000	0	0	0	0
China	Asphalt Plant of Liaohe Oil Field	Panjin	30,123	0	0	0	0	0	0
China	Baling Petrochemical	Baling	100,411	12,000	50,000	9,000	2,000	0	0
China	Baoding Petrochemical	Boading	8,033	0	0	0	0	0	0
China	Cangzhou Oil Refining	Cangzhou	24,099	0	9,000	0	0	0	0
China	Dagang Refinery	Dagang	20,082	0	0	0	0	0	0
China	Dalian Petrochemical	Dalian	142,584	0	70,000	20,000	2,000	0	0
China	Daqing Chemical Plant	Daqing	6,025	0	0	0	0	0	0
China	Daqing Petrochemical	Daqing	110,452	13,000	14,000	8,000	1,000	1,500	0
China	Duzishan Refining	Duzishan	66,000	8,000	12,000	8,000	0	0	0
China	Fujian Oil Refining	Fujian	50,205	10,000	16,000	0	0	0	0
China	Fushun Petrochemical	Fushun	174,715	35,000	66,000	8,000	3,000	0	0
China	Golmud Refinery	Qinhau	20,082	0	0	0	0	0	0
China	Guangzhou Petrochemical	Guangzhou	104,000	0	44,000	0	1,000	0	0
China	Hangzhou Refinery	Hangzhou	3,213	0	0	0	0	0	0

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TABLE 4.7-1 (CONTINUED)
REGIONAL REFINERY CAPACITY, FAR EAST
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
China	Harbin Refinery	Harbin	30,123	0	6,000	0	0	0	0
China	Huabei Chemical Pharmaceutical Plant	Shijiazhuang	4,016	0	0	0	0	0	0
China	Jianghan Petrochemical Plant	Qianjiang	2,410	0	0	0	0	0	0
China	Jiangnan Refinery	Jilin	6,025	0	0	0	0	0	0
China	Jilin Refinery	Qiangou	3,012	0	0	0	0	0	0
China	Jinan Oil Refining	Jinan	60,247	0	22,000	0	0	0	0
China	Jingmen Oil Refining	Jingmen	100,411	8,000	20,000	8,000	0	0	0
China	Jinling Petrochemical	Jinling	134,000	12,000	44,000	16,600	1,000	0	0
China	Jinxi Chemical	Jinxi	100,411	0	24,000	0	1,200	0	0
China	Jinzhou Petrochemical	Jinzhou	110,452	20,000	16,000	0	0	0	0
China	Jiujiang Oil Refining	Jiujiang	50,205	0	24,000	8,000	0	0	0
China	Karamay Refinery	Karamay	33,136	0	0	0	0	0	0
China	Lanzhou Chemical Industry Corp.	Lanzhou	17,000	0	0	0	0	0	0
China	Lanzhou Refining	Lanzhou	100,411	0	24,000	0	1,000	0	0
China	Liaoyang Chemical Fiber Corp.	Liaoyang	56,300	0	24,000	0	0	*1,400*	0
China	Linyuan Refinery	Linyuan	30,123	0	17,000	0	0	0	0
China	Luoyang Oil Refining	Luoyang	104,427	0	40,000	0	2,000	0	0
China	Majiatan Refinery	Lingwu	2,008	0	0	0	0	0	0
China	Maling Refinery	Qingyang	6,025	0	0	0	0	0	0
China	Maoming Petrochemical	Maoming	170,699	12,000	32,000	16,000	1,000	1,000	0
China	Mudanjiang Dongfanghong Refinery	Mudanjiang	4,016	0	0	0	0	0	0
China	Nanchong Refinery	Nanchong	3,012	0	0	0	0	0	0
China	Qianguo Oil Refining	Qianguo	30,123	0	24,000	0	0	0	0
China	Qilu Petrochemical	Qilu	160,658	16,000	46,000	42,000	3,000	0	0
China	Qingdao Petrochemical Plant	Qingdao	13,053	0	0	0	0	0	0
China	Henan Oil Administration	Nanyang	2,410	0	0	0	0	0	0
China	Jilin Petrochemical Co.	Jilin	86,353	0	0	0	0	0	0
China	Shanghai Gaoqiao Petrochemical	Shanghai Gaoqiao	146,000	10,000	38,000	0	1,000	0	0
China	Shanghai Petrochemical	Jinshan	106,436	0	0	18,000	2,400	4,400	0
China	Shengli Heavy Oil Plant	Dongying	20,082	0	0	0	0	0	0

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TABLE 4.7-1 (CONTINUED)
REGIONAL REFINERY CAPACITY, FAR EAST
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
China	Shengli Refinery	Dongying	3,012	0	0	0	0	0	0
China	Shijia Oil Refining	Shijiazhuang	70,000	10,000	24,000	0	1,000	0	0
China	Shongyuan Refinery	Puyang	3,012	0	0	0	0	0	0
China	Tianjin Petrochemical	Tianjin	74,000	0	35,000	0	1,000	2,000	0
China	Tianyang Refinery	Tianyang	1,004	0	0	0	0	0	0
China	Urumqi General Petrochemical	Wulumuqi	50,205	8,000	16,000	0	0	0	0
China	West Pacific Petrochemical	Dalian	95,000	0	37,800	0	2,250	0	0
China	Wuhan Oil Refining	Wuhan	50,205	0	20,000	0	1,000	0	0
China	Yanchang Oil & Mineral	Yanchang	14,058	0	0	0	0	0	0
China	Yangzi Petrochemical	Yangzi	60,247	0	21,000	24,000	0	0	0
China	Yanshan Petrochemical	Yanshan	140,575	0	48,000	0	1,000	0	0
China	Yumen Refinery	Yumen	30,123	0	0	0	0	0	0
China	Zepu Petrochemical Plant	Zepu	3,012	0	0	0	0	0	0
China	Zhenhai Petrochemical	Zhenhai	140,575	8,000	28,200	0	1,000	0	0
India	Bharat Petroleum CL	Mahul Bombay	134,860	0	28,755	0	0	13,000	0
India	Bongaigaon Refinery	Bongaigaon Assam	27,110	9,675	0	0	0	694	0
India	Cochin Refineries Ltd.	Cochin	151,000	0	27,000	0	0	12,000	0
India	Hindustan Petroleum CL	Mahul Bombay	110,452	0	12,000	0	0	0	0
India	Hindustan Petroleum CL	Mangalore	60,000	0	0	18,900	0	0	0
India	Hindustan Petroleum CL	Visakhapatnam	90,369	0	19,200	0	0	0	0
India	IBP CL	Numaligarh	123,500	0	0	0	0	0	0
India	Indian Oil CL	Barauni	65,800	20,000	0	0	0	0	0
India	Indian Oil CL	Digboi	11,700	850	0	0	0	0	0
India	Indian Oil CL	Gawahati	19,920	6,000	0	0	0	0	0
India	Indian Oil CL	Haldia	61,000	0	0	0	0	0	0
India	Indian Oil CL	Koyali	185,100	0	20,000	25,000	0	6,000	0
India	Indian Oil CL	Mathura	156,000	0	20,000	0	0	0	0
India	Madras Refineries Ltd.	Madras	130,660	0	11,250	0	0	0	0

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TABLE 4.7-1 (CONTINUED)
REGIONAL REFINERY CAPACITY, FAR EAST
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Indonesia	Pertamina	Balikpapan	240,920	0	0	49,500	0	0	0
Indonesia	Pertamina	Balongan (EXOR-I)	125,000	0	83,000	0	0	0	0
Indonesia	Pertamina	Cepu	3,420	0	0	0	0	0	0
Indonesia	Pertamina	Cilacap	285,000	0	0	0	0	0	0
Indonesia	Pertamina	Dumai	114,000	32,580	0	50,220	0	0	0
Indonesia	Pertamina	Musi	133,600	0	18,450	0	16,200	0	0
Indonesia	Pertamina	Pangakalan Brandan	4,750	0	0	0	0	0	0
Indonesia	Pertamina	Sungaipakning	47,500	0	0	0	0	0	0
Indonesia	Pertamina	Wonokomo	3,000	0	0	0	0	0	0
Japan	Cosmo Oil CL	Chiba	228,000	0	31,500	0	0	0	0
Japan	Cosmo Oil CL	Sakai	104,500	0	19,800	0	7,200	0	0
Japan	Cosmo Oil CL	Yokkaichi City	147,250	0	22,500	0	0	0	0
Japan	Cosmo Oil CL	Sakaide	133,000	0	17,100	0	0	0	0
Japan	Fuji Oil CL	Sodegaura	153,900	0	13,950	21,600	0	7,402	0
Japan	General Sekiyu Seisei KK	Sakai	140,400	0	36,000	0	0	19,800	0
Japan	Idemitsu Kosan CL	Chita, Aichi	152,000	0	56,000	0	9,000	0	0
Japan	Idemitsu Kosan CL	Himeji	133,000	0	0	0	0	0	0
Japan	Idemitsu Kosan CL	Ichihara, Chiba	237,500	0	37,800	10,440	0	12,060	0
Japan	Idemitsu Kosan CL	Tokuyama	114,000	0	22,500	0	0	0	0
Japan	Idemitsu Kosan CL	Tomakomai	123,500	0	23,400	13,500	0	0	0
Japan	Japan Energy	Chita	86,000	0	15,300	0	0	15,300	0
Japan	Japan Energy	Funakawa	6,000	0	0	0	0	0	0
Japan	Japan Energy	Mizushima	171,000	20,800	34,400	0	7,200	0	0
Japan	Kainan Petroleum Refining CL	Kaiwan City	50,000	0	0	0	0	0	0
Japan	Kashima Oil CL	Kashima	171,000	0	24,300	0	0	2,900	0
Japan	Koa Oil CL	Marifu	127,000	19,000	22,000	0	0	7,500	0
Japan	Koa Oil CL	Osaka	104,000	0	25,000	0	4,000	2,100	0
Japan	Kyenus Sekiyu Seisei KK	Kawasaki	66,500	0	0	0	0	0	0
Japan	Kyokuto Petroleum Ltd.	Chiba	143,000	0	28,000	35,000	0	0	0
Japan	Kyushu Oil CL	Oita	130,000	0	16,500	11,000	0	0	0

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TABLE 4.7-1 (CONTINUED)
REGIONAL REFINERY CAPACITY, FAR EAST
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Japan	Mitsubishi Oil CL	Kawasaki	75,000	0	0	0	0	0	0
Japan	Mitsubishi Oil CL	Mizushima	250,000	0	60,000	11,000	7,600	12,800	0
Japan	Nansei Sekiyu KK	Nishihara	100,000	0	0	0	0	0	0
Japan	Nihonkai Oil CL	Toyama	60,000	0	0	0	0	0	0
Japan	Nippon Oil CL	Niigata	24,700	0	4,500	0	0	0	0
Japan	NPRC	Muroran	161,500	0	20,700	36,000	0	0	0
Japan	NPRC	Negishi	365,750	0	63,900	0	3,960	0	0
Japan	Nippon Petroleum Refining CL	Nakagusuku	0	0	0	0	0	0	0
Japan	Nippon Petroleum Refining CL	Yokohama (Dismantled)	0	0	0	0	0	0	0
Japan	Nippon Refining	Kudamatsu	0	0	0	0	0	0	0
Japan	Okinawa Sekiyu Seisei	Yonashiro	110,000	0	0	0	0	0	0
Japan	Seibu Oil CL	Yamaguchi	114,000	0	19,800	0	0	0	0
Japan	Showa Shell Sekiyu KK	Kawasaki	110,100	0	0	0	0	3,300	0
Japan	Showa Shell Sekiyu KK	Niigata	36,700	0	0	0	0	0	0
Japan	Showa Yokkaichi Sekiyu CL	Yokkaichi	220,300	0	22,600	0	0	5,500	0
Japan	Taiyo Oil CL	Ehime	84,550	0	0	16,200	0	11,800	0
Japan	Teiseki Topping Plant	Kubiki	4,190	0	0	0	0	0	0
Japan	Toa Oil CL	Kawasaki	61,750	21,600	27,000	0	0	0	0
Japan	Toho Oil CL	Owase	35,000	0	0	0	0	0	0
Japan	Tohoku Oil CL	Sendai	83,900	0	25,000	0	0	0	0
Japan	Tonen	Kawasaki	217,350	0	79,380	0	6,615	0	0
Japan	Tonen	Wakayama	156,870	0	34,020	0	2,079	0	0
Korea N.	Government	Paengma-ri	29,000	0	0	0	0	0	0
Korea N.	Government	Sonbong	42,000	0	0	0	0	1,000	0
Korea S.	Hanhwa	Inchon	261,250	0	0	0	0	18,000	0
Korea S.	Hyundai	Busan	0	0	0	0	0	0	0
Korea S.	Hyundai Oil Ref Co.	Daesan	294,500	19,000	0	22,000	0	0	0
Korea S.	LG-Caltex	Yosu	570,000	0	63,000	0	0	20,700	0
Korea S.	Ssangyong Oil Refining CL	Onsan	418,950	0	0	27,000	0	9,600	0
Korea S.	Yukong Ltd.	Ulsan	769,500	0	45,000	27,000	5,400	27,900	0

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TABLE 4.7-1 (CONTINUED)
REGIONAL REFINERY CAPACITY, FAR EAST
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Malaysia	Esso Malaysia	Port Dickson	80,000	0	0	0	0	0	0
Malaysia	Petronas	Melaka	100,000	0	0	0	0	0	0
Malaysia	Petronas	Kerteh	75,000	0	0	0	0	0	0
Malaysia	Sarawak Shell Berhad	Luton	45,000	0	0	0	0	0	0
Malaysia	Shell Refining Co. Berhad	Port Dickson	105,000	0	0	0	0	0	0
New Zealand	New Zealand Refining	Whangarei	91,200	0	0	24,300	0	0	0
Pakistan	Attock Refinery Ltd.	Rawalpindi	28,975	0	0	0	0	0	0
Pakistan	National Refinery Ltd.	Karachi	62,050	0	0	0	0	0	0
Pakistan	Pakistan Refinery Ltd.	Karachi	46,300	0	0	0	0	0	0
Philippines	Caltex (Philippines) Inc.	Batangas	72,000	0	12,500	0	0	0	0
Philippines	Petron Corp.	Limay	147,250	0	13,500	0	0	0	0
Philippines	Pilipinas Shell Petroleum	Tabangao	154,000	0	0	0	0	0	0
Philippines	Philippine Petroleum Corp.	Pililla	0	0	0	0	0	0	0
Singapore	BP Refinery Singapore PL	Pasir Panjang	0	0	0	0	0	0	0
Singapore	Esso Singapore PL	Pulau Ayer Chawan	227,000	0	0	4,400	0	0	0
Singapore	Mobil Oil Singapore PL	Jurong	255,000	0	0	26,000	0	15,000	0
Singapore	Shell Eastern Petroleum Ltd.	Pulau Bukom	405,000	0	28,600	28,600	3,000	0	0
Singapore	Singapore Refining Co. Pte. Ltd.	Pulau Merlimau	270,000	0	31,000	30,300	4,200	0	0
Sri Lanka	Ceylon Petroleum Corp.	Sapugaskanda	47,500	0	0	0	0	0	0
Taiwan	Chinese Petroleum Corp.	Kaohsiung	570,000	16,000	50,000	18,080	3,200	60,000	0
Taiwan	Chinese Petroleum Corp.	Taoyuan	200,000	0	0	0	0	0	0
Thailand	Bangchak Petroleum	Bangkok	120,000	0	0	0	0	0	0
Thailand	Esso Standard Thailand Ltd.	Sriracha	166,000	0	27,000	0	0	0	0
Thailand	Fang Refining	Fang	1,700	0	0	0	0	0	0
Thailand	Rayong Refining	Rayong	145,000	0	0	40,000	0	0	0
Thailand	Star Petroleum	Map Ta Phut	123,500	0	33,300	0	0	0	0
Thailand	Thai Oil CL	Sriracha	207,000	0	11,200	19,900	0	0	0
Thailand	Thai Petrochemical Co.	Rayong	65,000	0	0	0	0	0	0
		TOTAL	**17,707,312**	**360,705**	**2,537,605**	**752,720**	**134,924**	**294,656**	**0**

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TABLE 4.7-2
REGIONAL REFINERY CAPACITY, FAR EAST- California Affiliates
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Australia	Mobil Oil Australia Ltd.	Adelaide (Port Stanvac)	68,400	0	0	0	0	0	0
Australia	Mobil Oil Australia Ltd.	Altona	102,600	0	23,000	0	2,500	0	0
Australia	Shell Refining (Australia) PL	Clyde	81,700	0	35,000	0	3,000	0	0
Australia	Shell Refining (Australia) PL	Geelong	104,500	0	38,000	0	4,500	0	0
Japan	Showa Shell Sekiyu KK	Kawasaki	110,100	0	0	0	0	3,300	0
Japan	Showa Shell Sekiyu KK	Niigata	36,700	0	0	0	0	0	0
Korea S.	LG-Caltex	Yosu	570,000	0	63,000	0	0	20,700	0
Malaysia	Esso Malaysia	Port Dickson	80,000	0	0	0	0	0	0
Malaysia	Shell Refining Co. Berhad	Port Dickson	105,000	0	0	0	0	0	0
Philippines	Caltex (Philippines) Inc.	Batangas	72,000	0	12,500	0	0	0	0
Singapore	Esso Singapore PL	Pulau Ayer Chawan	227,000	0	0	4,400	0	0	0
Singapore	Mobil Oil Singapore PL	Jurong	255,000	0	0	26,000	0	15,000	0
Singapore	Shell Eastern Petroleum Ltd.	Pulau Bukom	405,000	0	28,600	28,600	3,000	0	0
Thailand	Esso Standard Thailand Ltd.	Sriracha	166,000	0	27,000	0	0	0	0
Thailand	Rayong Refining	Rayong	145,000	0	0	40,000	0	0	0
Thailand	Star Petroleum	Map Ta Phut	123,500	0	33,300	0	0	0	0
		TOTAL	**2,652,500**	**0**	**260,400**	**99,000**	**13,000**	**39,000**	**0**

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TABLE 4.8-1
REGIONAL REFINERY CAPACITY, OTHER US
(Barrels per Stream Day)

Company	Location	State	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
ARCO	Kuparuk	AK	12,000	0	0	0	0	0	0
ARCO	Prudhoe Bay	AK	15,000	0	0	0	0	0	0
Mapco Petroleum	North Pole	AK	130,000	0	0	0	0	2,500	0
Petro Star Inc.	North Pole	AK	14,000	0	0	0	0	0	0
Petro Star Inc.	Valdez	AK	40,000	0	0	0	0	0	0
Tesoro Petroleum	Kenai	AK	72,000	0	0	9,000	0	0	0
Berry Petroleum Co.	Stevens	AR	6,700	0	0	0	0	0	0
Cross Oil	Smackover	AR	6,000	0	0	0	0	0	0
Lion Oil Co.	El Dorado	AR	52,500	0	19,100	0	5,000	0	0
Conoco	Denver/Commerce City	CO	57,500	0	19,000	0	0	0	0
Total Petroleum	Commerce City/Denver	CO	28,000	0	8,000	0	0	0	0
Star Enterprise	Delaware City	DE	140,000	41,850	63,000	17,100	8,190	1,260	0
CITGO	Savannah	GA	28,000	0	0	0	0	0	0
Young Refining	Douglasville	GA	6,000	0	0	0	0	0	0
BHP Hawaii Inc.	Ewa Beach/Kapolei	HA	95,000	0	0	18,000	0	0	0
Chevron	Barbers Point	HA	54,000	0	21,000	0	4,000	0	0
Clark Oil	Blue Island	IL	66,500	0	23,800	8,500	5,700	*0*	0
Clark Oil	Hartford	IL	57,000	13,000	24,700	0	7,600	0	0
Marathon Oil	Robinson	IL	166,000	24,200	43,000	21,000	11,500	0	0
Mobil Oil	Joliet	IL	203,700	43,800	93,500	0	26,300	0	0
Shell Wood River	Wood River	IL	271,000	0	85,000	28,500	20,500	3,500	0
Uno-Ven Co.	Lemont	IL	145,350	25,110	52,200	0	16,200	3,150	0
Amoco Oil	Whiting	IN	410,000	30,400	149,200	0	30,400	14,300	0
Countrymark Cooperative	Mt. Vernon	IN	22,000	0	7,850	0	1,700	0	0
Laketon Refining Corp.	Laketon	IN	3,990	0	0	0	0	0	0
Farmland Industries	Coffeyville	KS	110,000	16,500	28,000	0	7,000	0	0
Natl Coop Ref Assn	McPherson	KS	73,600	20,800	19,800	9,400	5,700	0	0
Texaco	El Dorado	KS	99,750	15,300	31,320	0	10,800	2,700	0
Ashland Petroleum	Catlettsburg	KY	219,300	0	97,000	0	11,640	5,820	0
Somerset Refinery	Somerset	KY	5,500	0	0	0	0	0	0
Lakeside Refining	Kalamazoo	MI	5,600	0	0	0	0	0	0
Marathon Oil	Detroit	MI	70,000	0	27,000	0	4,000	0	0
Total Petroleum	Alma	MI	45,600	0	18,500	0	4,600	0	0

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TABLE 4.8-1 (CONTINUED)
REGIONAL REFINERY CAPACITY, OTHER US
(Barrels per Stream Day)

Company	Location	State	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Ashland Petroleum	St. Paul Park	MN	69,000	0	22,310	0	5,335	0	0
Koch Refining	Rosemount	MN	286,000	66,000	86,500	0	12,000	0	0
Cenex	Laurel	MT	41,450	0	13,500	0	3,780	0	0
Conoco	Billings	MT	49,400	11,700	17,100	0	5,400	0	0
Exxon	Billings	MT	46,000	7,300	20,000	4,500	3,200	0	0
Montana Refining Co.	Great Falls	MT	7,000	0	2,400	0	700	0	0
Amoco Oil	Mandan	ND	58,000	0	24,700	0	4,200	0	0
Amerada-Hess	Port Reading	NJ	0	0	54,000	0	4,050	0	0
Chevron	Perth Amboy	NJ	80,000	0	0	0	0	0	0
CITGO	Thorofare	NJ	80,000	0	0	0	0	0	0
Coastal Ref. & Mkt.	Westville	NJ	125,000	0	50,000	0	3,500	6,500	0
Mobil Oil	Paulsboro	NJ	149,000	22,600	43,700	0	10,300	0	0
Tosco	Linden	NJ	240,000	0	135,000	0	12,000	0	0
Petrosource *	Tonopah/Eagle Springs	NV	7,000	0	0	0	0	0	0
Ashland Petroleum	Canton	OH	65,900	0	24,250	0	6,790	0	0
BP Oil Co.	Lima	OH	161,500	18,900	33,300	21,600	6,500	4,950	0
BP Oil Co.	Toledo	OH	147,250	18,900	54,000	25,200	10,350	0	0
Sun Refining & Mkt.	Toledo	OH	125,000	0	62,000	28,200	9,000	9,000	0
Conoco	Ponca City	OK	155,000	21,500	53,000	0	12,000	0	0
Gary-Williams Energy Corp.	Wynnewood	OK	45,000	0	17,500	4,500	4,500	0	0
Sinclair Oil	Tulsa	OK	50,000	0	16,200	0	2,700	0	0
Sun Refining & Mkt.	Tulsa	OK	85,000	7,200	0	0	0	0	0
Total Petroleum	Ardmore	OK	68,000	0	23,000	0	6,200	0	0
Pennzoil Products	Rouseville	PA	15,700	0	0	0	0	0	0
Sun Refining & Mkt.	Marcus Hook	PA	175,000	0	87,000	0	10,000	19,200	0
Sun Refining & Mkt.	Philadelphia-Girard Pt.	PA	177,000	0	59,500	0	16,700	3,700	0
Sun Refining & Mkt.	Philadelphia-Pt. Breeze	PA	130,000	0	36,000	27,000	5,400	0	0
Tosco	Marcus Hook	PA	180,500	0	47,700	18,900	10,800	0	0
United Refining Co.	Warren	PA	66,700	0	23,000	0	3,500	0	0
Witco Chemical Co.	Bradford	PA	10,000	0	0	0	0	0	0
Mapco Petroleum	Memphis	TN	105,000	0	50,000	0	6,000	0	0
Crysen Refining	Woods Cross	UT	12,500	0	0	4,000	0	0	0
Phillips Petroleum Co.	Woods Cross	UT	25,000	0	7,700	0	2,200	0	0
Amoco Oil	Yorktown	VA	56,700	18,000	25,700	0	0	0	0
		TOTAL	**5,543,190**	**423,060**	**1,920,030**	**236,400**	**357,935**	**74,080**	**0**

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TABLE 4.8-2
REGIONAL REFINERY CAPACITY, OTHER
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Africa									
Algeria	NAFTEC	Skikida	310,000	0	0	0	0	4,500	0
Algeria	NAFTEC	Arzew	60,000	0	0	0	0	0	0
Algeria	NAFTEC	Hassi Messoud	30,000	0	0	0	0	0	0
Algeria	NAFTEC	El-Marrach	58,000	0	0	0	0	0	0
Algeria	NAFTEC	In Amenas	7,000	0	0	0	0	0	0
Angola	Cabinda Gulf Oil Co.	Cabinda	1,400	0	0	0	0	0	0
Angola	Fina	Luanda	32,100	0	0	0	0	0	0
Cameroon	Sonara-National Refining CL	Pointe Limboh Limbe	42,000	0	0	0	0	0	0
Congo	Coraf	Pointe-Noire	21,000	0	0	2,000	0	0	0
Cote d'Ivoire	Ste. Ivoirienne de Raffinage	Abidjan	54,000	0	0	13,000	0	0	0
Cote d'Ivoire	Ste. Multinationale de Bitumes	Abidjan	10,000	0	0	0	0	0	0
Egypt	Alexandria Petroleum Co.	Alexandria (El-Mex)	94,860	0	0	0	0	603	0
Egypt	Ameriya Petroleum Company	Ameriya	68,620	0	0	0	9,000	700	0
Egypt	Cairo Petroleum Company	Mostorod	141,160	0	0	0	0	0	0
Egypt	Cairo Petroleum Company	Tanta	29,000	0	0	0	0	0	0
Egypt	El-Nasr Petroleum Co.	Suez	99,300	0	0	0	0	0	0
Egypt	El-Nasr Petroleum Co.	Wadi-Feran	7,060	0	0	0	0	0	0
Egypt	El-Nasr Petroleum Co.	Asyut	43,540	0	0	0	0	0	0
Egypt	Suez Petroleum Company	Suez	62,520	16,470	0	0	0	0	0
Ethiopia	Ethiopian Petroleum Corp.	Assab	18,000	0	0	0	0	0	0
Gabon	Ste. Gabonaise de Raffinage	Port Gentil	17,300	0	0	0	0	0	0
Ghana	Ghanaian Italian Petroleum CL	Tema	26,600	0	0	0	0	0	0
Kenya	Kenya Petroleum Refineries Ltd.	Mombasa	85,500	0	0	0	0	0	0
Liberia	Liberia Petroleum Refining	Monrovia	0	0	0	0	0	0	0
Libya	NOC	Sarir	10,000	0	0	0	0	0	0
Libya	NOC	Azzawiya	120,000	0	0	0	0	0	0
Libya	NOC	Mersa El-Brega	8,400	0	0	0	0	0	0
Libya	NOC	Ras Lanuf	220,000	0	0	0	0	0	0
Libya	NOC	Tobruk	20,000	0	0	0	0	0	0
Libya	NOC	Sebha	0	0	0	0	0	0	0

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TABLE 4.8-2 (CONTINUED)
REGIONAL REFINERY CAPACITY, OTHER
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Madagascar	Solima	Tamatave Solima	15,000	0	0	0	0	0	0
Mauritania	SAMIR	Nouadhibou	23,750	0	0	0	0	0	0
Morocco	SAMIR	Mohammadia	129,000	0	0	0	0	0	0
Morocco	Ste. Cherifienne des Petroles	Sidi Kacem	26,600	0	5,040	0	0	0	0
Nigeria	Nigerian Petroleum Refining CL	Port Harcourt (Rivers State)	150,000	0	40,000	0	7,020	0	0
Nigeria	Nigerian Petroleum Refining CL	Warri	118,750	0	24,700	0	2,850	0	0
Nigeria	Nigerian Petroleum Refining CL	Kaduna	104,500	0	18,000	0	0	0	0
Nigeria	Nigerian Petroleum Refining CL	Port Harcourt (Alesa Eleme)	60,000	0	0	0	0	0	0
Senegal	Ste. Africaine de Raffinage	M'Bao (Dakar)	17,000	0	0	0	0	0	0
Sierra Leone	Sierra Leone Petroleum Refining Co.	Freetown	10,000	0	0	0	0	0	0
Somalia	Iraqsoma Ref. Co.	Mogadishu	10,000	0	0	0	0	0	0
South Africa	Caltex Oil SA PL	Cape Town	106,400	0	22,500	0	0	0	0
South Africa	Genref	Durban	85,000	0	15,000	0	2,200	0	0
South Africa	National Petroleum Refiners of South Africa PL	Sasolburg OFS	86,000	0	18,000	23,500	3,300	0	0
South Africa	Shell and BP South Africa Petroleum Refineries PL	Durban	156,750	0	31,500	0	2,700	*0*	0
South Africa	South African Oil Refinery (Pty.) Limited	Durban	0	0	0	0	0	0	0
Sudan	Concorp	Abu Gabra	2,000	0	0	0	0	0	0
Sudan	GEPCO	Port Sudan	21,700	0	0	0	0	0	0
Tanzania	Tanzanian & Italian Petroleum Refining CL	Kigamboni Dar es Salaam	15,865	0	0	0	0	0	0
Tunisia	STIR	Bizerte	34,000	0	0	0	0	0	0
Zaire	Sozir	Kinlao-Muanda	17,000	0	0	0	0	0	0
Zambia	Indeni Petroleum Refinery CL	Ndola	23,750	0	0	0	0	0	0
Zimbabwe	Central African Petroleum Refineries (Pty.) Limit.	Mutare (Closed 1985)	0	0	0	0	0	0	0

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TABLE 4.8-2 (CONTINUED)
REGIONAL REFINERY CAPACITY, OTHER
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Canada									
Canada	Chevron Canada Ltd.	North Burnaby	50,000	0	18,000	0	3,000	0	0
Canada	Consumers' Cooperative Refineries Ltd.	Regina	45,200	8,300	17,600	10,800	0	0	0
Canada	Husky Oil Operations Ltd.	Lloydminster	23,500	0	0	0	0	0	0
Canada	Husky Oil Operations Ltd.	Prince George	9,500	0	3,300	0	0	0	0
Canada	Imperial Oil Ltd.	Dartmouth	84,360	0	28,500	0	0	0	0
Canada	Imperial Oil Ltd.	Edmonton	176,000	0	50,000	0	16,000	0	0
Canada	Imperial Oil Ltd.	Ioco	0	0	0	0	0	0	0
Canada	Imperial Oil Ltd.	Nanticoke	112,000	0	40,850	0	11,000	0	0
Canada	Imperial Oil Ltd.	Norman Wells	0	0	0	0	0	0	0
Canada	Imperial Oil Ltd.	Sarnia	119,000	23,300	25,650	13,000	7,400	5,000	0
Canada	Irving Oil Ltd.	St. John	237,500	0	24,000	29,700	5,000	0	0
Canada	North Atlantic Refining Ltd.	Come By Chance	99,750	0	0	31,500	0	0	0
Canada	Novacor Chemicals (Canada) Ltd.	Corunna	80,000	0	0	0	0	10,200	0
Canada	Parkland Refining Ltd.	Bowden	6,000	0	0	0	0	0	0
Canada	Petro-Canada Products Inc.	Edmonton	119,000	7,500	34,300	18,700	12,600	0	0
Canada	Petro-Canada Products Inc.	Mississauga	0	0	0	10,300	0	0	0
Canada	Petro-Canada Products Inc.	Montreal	92,500	0	18,400	20,900	2,700	8,350	0
Canada	Petro-Canada Products Inc.	Oakville	80,500	0	25,400	0	3,300	0	0
Canada	Petro-Canada Products Inc.	Port Moody	0	0	0	0	0	0	0
Canada	Petro-Canada Products Inc.	Taylor	0	0	0	0	0	0	0
Canada	Saskoil	Moose Jaw	12,000	0	0	0	0	0	0
Canada	Shell Canada Ltd.	Burnaby	0	0	0	0	0	0	0
Canada	Shell Canada Ltd.	Montreal	125,500	0	24,000	11,700	2,500	0	0
Canada	Shell Canada Ltd.	Sarnia	71,400	0	14,400	6,750	0	2,700	0
Canada	Shell Canada Ltd.	Scotford	75,700	0	0	40,500	0	5,300	0
Canada	Suncor Inc.	Sarnia	83,400	0	15,500	23,700	5,600	9,500	0
Canada	Turbo Resources Ltd.	Balzac	0	0	0	0	0	0	0
Canada	Ultramar	Halifax	0	0	0	0	0	0	0
Canada	Ultramar Canada Inc.	St. Romuald	150,000	0	47,000	0	0	0	0

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TABLE 4.8-2 (CONTINUED)
REGIONAL REFINERY CAPACITY, OTHER
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Eastern Europe									
Albania	Government	Balish	20,000	0	0	0	0	0	0
Albania	Government	Fier	10,000	0	0	0	0	0	0
Albania	Government	Cerrik	10,000	0	0	0	0	0	0
Albania	Government	Kucove (Stalin)	10,000	0	0	0	0	0	0
Bosnia	Energoinvest Sarajevo (Destroyed by War)	Slavonski Brod (Bosanski)	0	0	0	0	0	0	0
Bulgaria	Government	Rest of Country	0	0	0	0	0	0	0
Bulgaria	Government-Owned Refineries	Ruse	2,000	0	0	0	0	0	0
Bulgaria	Neftochim	Bourgas	240,000	0	32,000	0	0	3,500	0
Bulgaria	PLAMA	Pleven	30,000	0	0	0	0	0	0
Croatia	INA-Rafinerija Nafte Rijeka	Rijeka	150,000	0	22,000	0	0	3,300	0
Croatia	INA-Rafinerija Nafte Sisak	Sisak	143,472	5,930	10,000	0	0	9,979	0
Croatia	Zagreg Refinery	Zagreb	803	0	0	0	0	0	0
Czech Republic	Chempetrol	Litvinov	100,000	0	0	22,000	0	5,000	0
Czech Republic	Kaucuk s.p.	Kralupy	66,850	0	0	0	0	0	0
Czech Republic	Koramo	Kolin	0	0	0	0	0	0	0
Czech Republic	Paramo	Pardubice	20,289	0	0	0	0	0	0
Czechoslovakia	Government	Rest of Country	0	0	0	0	0	0	0
Hungary	Dunai KV	Szazhalombatta	161,000	0	24,000	0	3,300	7,100	0
Hungary	Tiszai KV	Leninvaros	61,000	0	0	0	0	0	0
Hungary	Zalai KV	Zalaegerszeg	10,000	0	0	0	0	0	0
Lithuania	Mazheiksky NPZ	Mazeikiai	240,000	0	41,063	0	0	0	0
Macedonia	Rafinerija Skopje	Skopje	51,180	0	0	0	0	0	0
Poland	Gdansk Zaklady Rafineryjne	Gdansk	60,000	0	0	0	0	0	0
Poland	Government	Rest of Country	0	0	0	0	0	0	0
Poland	Mazoweckie Zadlady Rafineryjne i Petrochemiczne	Plock (MZRIP)	260,000	0	46,000	0	3,000	3,500	0
Poland	Podkarpackie Zaklady Rafineryjne	Jaslo (Carpathian)	3,000	0	0	0	0	0	0
Poland	Rafineria Jafy Jedlicze	Jedlicze	7,200	0	0	0	0	0	0
Poland	Rafineria Nafy Gilmar	Gorlice (Gilmar)	3,400	0	0	0	0	0	0
Poland	Rafineria Nafy Trzebinin	Trzebina	7,000	0	0	0	0	0	0
Poland	Salaskie Zaklady Rafineryjne	Dziedzice (Silesian)	14,000	0	0	0	0	0	0

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TABLE 4.8-2 (CONTINUED)
REGIONAL REFINERY CAPACITY, OTHER
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Eastern Europe									
Romania	Arpechim SA	Pitesti	70,288	0	19,178	1,534	0	1,591	0
Romania	Astra SA	Ploiesti	56,000	8,600	0	0	0	0	0
Romania	Crisiana	Barcau	8,000	0	0	0	0	0	0
Romania	Darmanesti Refinery	Darmanesti	33,000	9,500	0	0	0	0	0
Romania	Lubrifin SA	Brasov	0	0	0	0	0	0	0
Romania	Petrobrazi SA	Ploiesti	159,000	39,000	23,000	0	0	4,000	4,500
Romania	Petromidia SA	Navodari	110,000	20,000	23,700	0	0	4,700	0
Romania	Petrotel SA	Ploiesti	104,000	11,480	20,900	0	2,300	0	0
Romania	Rafo SA	Onesti	87,358	5,638	23,014	0	0	6,803	0
Romania	Steaua SA	Cimpina	9,272	0	0	0	0	0	0
Romania	Vega SA	Ploiesti	18,516	0	0	0	0	0	0
Serbia	Belgrade Lube Refinery	Obrenovac (Belgrade)	1,000	0	0	0	0	0	0
Serbia	Naftgas-Petroleum Industries	Pancevo	108,000	0	21,000	0	2,100	2,904	0
Serbia	Naftgas-Petroleum Industries	Novi Sad	60,246	0	0	0	0	0	0
Slovakia	Petrochemica Dubova	Banska Bystrica	0	0	0	0	0	0	0
Slovakia	Slovnaft	Bratislava	115,000	0	0	16,970	0	3,164	0
Slovakia	Slovnaft	Vojany	0	0	0	0	0	0	0
Slovenia	Lendava Refinery	Lendava	12,000	0	0	0	0	0	0

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TABLE 4.8-2 (CONTINUED)
REGIONAL REFINERY CAPACITY, OTHER
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Former Soviet Union									
Azerbaijan	Bakinsky	Bakinsky	238,978	0	0	0	0	0	0
Azerbaijan	Novo-Bakinsky	Bakinsky	202,830	38,529	71,342	0	930	0	0
Belarus	Mozyrsksky NPZ	Mozyr	323,323	0	0	12,000	0	0	0
Belarus	Novopolotsknefteorgsintez	Novopolotsk	401,644	0	0	0	0	5,112	0
Georgia	Batumsky NPZ	Batumi	106,340	0	0	0	0	0	0
Kazakhstan	Chimkentsky NPZ	Chimkent	160,000	0	0	0	0	0	0
Kazakhstan	Gyr'yevsky NPZ	(Guryev) Atyrau	104,427	13,720	0	0	0	0	0
Kazakhstan	Pavlodarsky	Pavlodar	162,666	11,277	38,356	0	0	0	0
Russia	Achinsky NPZ	Achinsk	146,584	0	0	0	0	0	0
Russia	Angarsknefteorgsintez	Angarsk	463,899	11,217	33,753	0	0	3,182	0
Russia	Government	Afipsky	28,115	0	0	0	0	3,680	0
Russia	Government	Novo-Groznyi	0	0	0	0	0	0	0
Russia	Government	Groznyi-Sheripov	40,164	0	0	0	0	0	0
Russia	Government	Ishimbai	0	0	0	0	0	0	0
Russia	Groznefteorgsintez	Grozny	389,595	0	38,356	0	0	0	0
Russia	Khabarovsky NPZ	Khabarovsk	114,468	0	0	0	0	0	0
Russia	Kirishinefteorgsintez	Kirishi	387,586	0	0	0	0	5,172	0
Russia	Komsomol'sky NPZ	Komsomolsk	116,477	9,679	0	0	0	0	0
Russia	Krasnodarnefteorgsintez	Krasnodar	34,140	0	0	0	0	0	0
Russia	Kuibyshevsky NPZ	Kuibyshev	120,493	0	18,795	0	832	0	0
Russia	Lukoil	Astrakhan	66,000	0	24,466	0	0	0	0
Russia	Lukoil	Kondpetroleum	6,000	0	0	0	0	0	0
Russia	Lukoil	Makhachkala	4,000	0	0	0	0	0	0
Russia	Lukoil	Urayneftegaz	2,000	0	0	0	0	0	0
Russia	Moskovsky NPZ	Moscow	242,995	0	38,356	0	0	0	0
Russia	Nizhnekamskneftekhim	Nizhnekamsk	120,493	0	0	0	0	0	0
Russia	Norsi Oil	Norsi	437,792	1,260	0	0	0	1,790	0
Russia	Novokuibyshevsky NPZ	Novo-Kuibyshev	309,266	28,192	13,616	0	0	2,188	0

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TABLE 4.8-2 (CONTINUED)
REGIONAL REFINERY CAPACITY, OTHER
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Former Soviet Union									
Azerbaijan	Bakinsky	Bakinsky	238,978	0	0	0	0	0	0
Azerbaijan	Novo-Bakinsky	Bakinsky	202,830	38,529	71,342	0	930	0	0
Belarus	Mozyrsksky NPZ	Mozyr	323,323	0	0	12,000	0	0	0
Belarus	Novopolotsknefteorgsintez	Novopolotsk	401,644	0	0	0	0	5,112	0
Georgia	Batumsky NPZ	Batumi	106,340	0	0	0	0	0	0
Kazakhstan	Chimkentsky NPZ	Chimkent	160,000	0	0	0	0	0	0
Kazakhstan	Gyr'yevsky NPZ	(Guryev) Atyrau	104,427	13,720	0	0	0	0	0
Kazakhstan	Pavlodarsky	Pavlodar	162,666	11,277	38,356	0	0	0	0
Russia	Achinsky NPZ	Achinsk	146,584	0	0	0	0	0	0
Russia	Angarsknefteorgsintez	Angarsk	463,899	11,217	33,753	0	0	3,182	0
Russia	Government	Afipsky	28,115	0	0	0	0	3,680	0
Russia	Government	Novo-Groznyi	0	0	0	0	0	0	0
Russia	Government	Groznyi-Sheripov	40,164	0	0	0	0	0	0
Russia	Government	Ishimbai	0	0	0	0	0	0	0
Russia	Groznefteorgsintez	Grozny	389,595	0	38,356	0	0	0	0
Russia	Khabarovsky NPZ	Khabarovsk	114,468	0	0	0	0	0	0
Russia	Kirishinefteorgsintez	Kirishi	387,586	0	0	0	0	5,172	0
Russia	Komsomol'sky NPZ	Komsomolsk	116,477	9,679	0	0	0	0	0
Russia	Krasnodarnefteorgsintez	Krasnodar	34,140	0	0	0	0	0	0
Russia	Kuibyshevsky NPZ	Kuibyshev	120,493	0	18,795	0	832	0	0
Russia	Lukoil	Astrakhan	66,000	0	24,466	0	0	0	0
Russia	Lukoil	Kondpetroleum	6,000	0	0	0	0	0	0
Russia	Lukoil	Makhachkala	4,000	0	0	0	0	0	0
Russia	Lukoil	Urayneftegaz	2,000	0	0	0	0	0	0
Russia	Moskovsky NPZ	Moscow	242,995	0	38,356	0	0	0	0
Russia	Nizhnekamskneftekhim	Nizhnekamsk	120,493	0	0	0	0	0	0
Russia	Norsi Oil	Norsi	437,792	1,260	0	0	0	1,790	0
Russia	Novokuibyshevsky NPZ	Novo-Kuibyshev	309,266	28,192	13,616	0	0	2,188	0

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TABLE 4.8-2 (CONTINUED)
REGIONAL REFINERY CAPACITY, OTHER
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
Russia	Novoufimsky	Novo-Ufa	379,553	7,142	22,247	0	2,814	0	0
Russia	NPO Grozneftekhim	Tuapse	46,189	0	0	0	0	0	0
Russia	Omsknefteorgsintez	Omsk	566,318	13,908	65,589	19,178	1,272	11,139	0
Russia	Orsknefteorgsintez	Orsk	158,649	0	0	0	1,125	0	0
Russia	Permnefteorgsintez	Perm	279,142	13,532	15,726	0	1,003	3,481	0
Russia	Russian Fuel Co JSC	Kutshui	8,000	0	0	0	0	0	0
Russia	Ryanzansky NPZ	Ryazan	361,479	0	18,219	0	0	4,078	0
Russia	Salavatnefteorgsintez	Salavat	247,011	0	21,096	0	1,174	1,591	0
Russia	Saratovsky NPZ	Saratov (Kreking)	176,723	0	0	0	0	0	0
Russia	Surgutgazprom	Surgut	88,000	0	0	0	0	0	0
Russia	Syzransky NPZ	Syzran	210,863	0	17,068	0	0	0	0
Russia	Ufimsky	Ufaneftekhim	234,962	0	38,356	0	0	0	0
Russia	Ufimsky CPSC	Ufimsky	251,027	0	17,260	19,178	0	10,542	0
Russia	Ukhtinsky NPZ	Ukhta	126,518	0	0	0	0	0	0
Russia	Urengoygazdobycha	Urengoy	9,000	0	0	0	0	0	0
Russia	Volgogradsky NPZ	Volgograd	188,733	24,809	0	0	0	1,830	0
Russia	Yakutgazprom	Yakutsk	2,500	0	0	0	0	0	0
Russia	Yaraslav-Mendeleev	Yaraslav	8,700	0	0	0	0	0	0
Russia	Yaroslavl'nefteorgsintez	Yaroslavnette	359,471	0	21,096	0	1,786	1,551	0
Turkmenistan	Charjousky NPZ	Chardzhou	120,493	0	0	0	0	0	0
Turkmenistan	Krasnovodsky NPZ	Krasnovodsk	116,477	28,568	15,151	0	1,028	0	0
Ukraine	Drogobychsky NPZ	Drogobych	78,321	3,195	0	0	0	0	0
Ukraine	Khersonsky NPZ	Kherson	172,707	12,028	0	0	0	0	0
Ukraine	Kievskoye NPO Masma	L'vov	8,000	0	0	0	0	0	0
Ukraine	Kremenchugnefteorgsintez Joint Stock Co.	Kremenchug	360,000	0	29,600	0	0	6,000	0
Ukraine	Lisichansky NPZ	Lisichansk	481,973	0	30,356	0	0	0	0
Ukraine	Nadvornyansky NPZ	Nadvornaya	74,304	6,954	0	0	0	0	0
Ukraine	Odessky	Odessa	78,321	0	0	0	0	0	0
Uzbekistan	Ferghananefteorgsintez	Ferghana	108,444	17,667	0	0	0	0	0
Uzbekistan	Government	Amtyari	66,271	0	0	0	0	0	0
		Total	**17,494,533**	**397,395**	**1,456,299**	**346,910**	**118,834**	**163,730**	**4,500**

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TABLE 4.8-3
REGIONAL REFINERY CAPACITY, OTHER US- California Affiliates
(Barrels per Stream Day)

Star Enterprise	Delaware City	DE	140,000	41,850	63,000	17,100	8,190	1,260	0
Chevron	Barbers Point	HA	54,000	0	21,000	0	4,000	0	0
Mobil Oil	Joliet	IL	203,700	43,800	93,500	0	26,300	0	0
Shell Wood River Refining Co.	Wood River	IL	271,000	0	85,000	28,500	20,500	3,500	0
Texaco	El Dorado	KS	99,750	15,300	31,320	0	10,800	2,700	0
Exxon	Billings	MT	46,000	7,300	20,000	4,500	3,200	0	0
Chevron	Perth Amboy	NJ	80,000	0	0	0	0	0	0
Mobil Oil	Paulsboro	NJ	149,000	22,600	43,700	0	10,300	0	0
	Total		**1,043,450**	**130,850**	**357,520**	**50,100**	**83,290**	**7,460**	**0**

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TABLE 4.8-4
REGIONAL REFINERY CAPACITY, OTHER- California Affiliates
(Barrels per Stream Day)

Country	Company	Location	Crude	Coking	FCC	Hydro-cracking	Alkylation	Aromatics	Isom
South Africa	Shell and BP South Africa Petroleum Refineries	Durban	156,750	0	31,500	0	2,700	0	0
		Total	**156,750**	**0**	**31,500**	**0**	**2,700**	**0**	**0**

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5. TECHNICAL ASPECTS OF MANUFACTURING REFORMULATED GASOLINE

Technical aspects of manufacturing CARB reformulated gasoline were used to segregate refineries according to their likelihood of being able to meet the CARB specifications. CARB gasoline specifications are the most restrictive automotive gasoline specifications in the world that are widely applied. Meeting the specifications requires refinery equipment not commonly found in all locations.

In this chapter the CARB specifications are reviewed and these specifications are contrasted with typical specifications in other parts of the world. Then the most important features of CARB gasoline blend stocks are identified. Next the key process units that are important to producing CARBOB are discussed. Finally, the problems that refiners in other regions might have in producing CARBOB are reviewed. These discussions set the stage for steps to quantify how much CARBOB refiners in other regions are likely to be able to produce.

5.1 REVIEW OF CARB GASOLINE SPECIFICATIONS

CARB gasoline can be blended using one of three options. First, the refinery may elect to meet “flat limits”. Second, the refinery may use averaging. Third, the refinery may use the predictive model.

The system of flat limits establishes a fixed set of gasoline quality criteria, shown in Table 5.1-1. The refiner or importer must ensure that each blend or cargo meets the fixed criteria.

TABLE 5.1-1
CARB REGULATIONS

Quality	Flat Limit
RVP PSIA Max	7
Sulfur PPM Max	40
Benzene Vol % Max	1
Olefin Vol % Max	6
Oxygen	
T50 Deg F Max	210
T90 Deg F Max	300
Aromatics Vol % Max	25

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As opposed to meeting fixed limits, a refiner or importer may satisfy CARB requirements by providing gasoline that meets CARB limits on average, even though any individual batch or cargo may not meet the average limits. In order to use this option, the refiner or importer must meet average limits that are somewhat more stringent than the flat limits.

Also, each cargo is limited in how far out of range it can be and there are “cap limits” that must not be exceeded by any individual batch or cargo. The averaging limits and cap limits are shown in Table 5.1-2.

TABLE 5.1-2
CARB REGULATIONS

Quality	Averaging Limit	Cap Limit
RVP PSIA Max		7
Sulfur PPM Max	30	80
Benzene Vol % Max	0.8	1.2
Olefin Vol % Max	4	10
Oxygen		2.7
T50 Deg F Max	200	220
T90 Deg F Max	290	330
Aromatics Vol % Max	22	30

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The predictive model allows refiners to meet CARB requirements by use of a complicated set of equations. The equations correlate vehicle emissions performance to fuel qualities. Refiners or importers may determine a set of specifications that have satisfactory emissions characteristics according to the predictive model and submit those specifications to CARB. Cap limits still apply and prevent complete freedom on any particular quality characteristic. The predictive model has proven to be very useful to refiners and is widely used to define quality characteristics of California gasoline.

5.1.1 Vapor Pressure

At 7 PSIA or about 48.3 kilopascals, the summertime Reid Vapor Pressure (RVP) specification of CARB gasoline is extremely low by international standards. California manufacturers have responded to these requirements by installing equipment to ensure thorough debutanization of most gasoline components and by depentanizing many streams. Summertime gasoline blending in California uses pentane for vapor pressure control, not the more common butane.

In most other parts of the world, summertime gasoline RVP limits are between 9 and 11.5 psia. These limits have been determined mostly by vehicle performance characteristics including the requirement to avoid gasoline vaporizing in the fuel lines, known as “vapor lock”.

5.1.2 Sulfur

CARB gasoline specifications have very low sulfur requirements. Gasoline in much of the world is blended to specifications of 1000 to 1500 ppm while the CARB flat limits call for 40 ppm. Manufacturing gasoline to such low sulfur levels requires desulfurizing most streams including straight run gasolines and FCC feed stocks and/or FCC gasolines.

5.1.3 Benzene

CARB's flat limits call for 1.0% benzene content. In most of the world benzene levels are much higher, up to 5% in some markets. In a few European markets lower benzene levels are being developed but refiners have yet to manufacture such low levels in most locations. Benzene limits are met either by controlling benzene precursor levels in reformer feed stocks or by benzene extraction or saturation. There is very little West Coast market for benzene so benzene extraction is not widely practiced in California. Benzene is a valuable commodity in areas with large petrochemical industries and so there are many benzene extraction plants around the world to satisfy petrochemical demand. Refiners in other parts of the world have not adopted the benzene control strategies based on precursor control or saturation employed by California refiners. Gulf Coast refineries which must produce gasoline with limited benzene content follow benzene control strategies similar to those employed in California.

5.1.4 Olefin

CARB's flat limits call for 6% olefin content. In most parts of the world there are no olefin specifications. Markets that rely on catalytic cracking conversion to manufacture gasoline and use FCC gasoline as a high volume blend stock would be expected to have difficulty meeting stringent olefin specifications. Olefins are produced by such cracking and are concentrated in FCC gasoline. Refiners that rely more heavily on hydrocracking technology would not find high olefin content in their gasoline pools since hydrocrackers do not produce olefins.

5.1.5 Oxygen

CARB specifications do not require any minimum oxygen content. Likewise most countries do not require oxygen in gasoline. A few countries have adopted minimum oxygen requirements, usually using MTBE or other ethers.

5.1.6 Distillation

CARB specifications call for limits on boiling point at the 50% distilled and 90% distilled levels, T50 and T90. These are more stringent than those encountered in most other markets. However, since many other markets maximize kerosene and distillate production rather than gasoline, meeting T90 and T50 limits may not represent a particularly troubling challenge to some refiners.

5.1.7 Aromatics

Aromatics content of CARB gasoline is limited to 25% in flat limits gasoline. Most other parts of the world do not have aromatics limits and gasoline aromatics level can be much higher. Aromatics are high in reformates and FCC gasolines, both mainstays of gasoline volume and production and octane enhancement in most countries.

5.2 ABILITY TO MEET CARB SPECIFICATIONS

Differences between CARB specifications and those found in potential exporting regions limit the ability of other areas to supply CARB gasoline. Potential exporting refiners have, as a group, been obligated to meet only much less stringent specifications. Refiners in locations outside California have not invested as heavily as California refiners have in the kinds of processing important to making CARB gasoline. As a result they cannot produce as much of their gasoline to meet CARB specifications as the California refiners can. From a blend stock point of view, they have fewer blend stocks with suitable qualities and more blend stocks with objectionable qualities.

Alkylate is the ideal CARB gasoline blend stock. Alkylate contains no olefins, no sulfur, no aromatics, no benzene and has low vapor pressure. Alkylate has attractive octane characteristics. There is no property relevant to CARB gasoline in which alkylate has poor characteristics. Alkylate from California refiners and that produced elsewhere is essentially the same in all respects.

There are other blend stocks which, though attractive from some points of view, have shortcomings for manufacturing CARB gasoline. These blend stocks often have different characteristics elsewhere than are found in their California counterparts.

Light hydrocrackate has virtually no sulfur, no benzene, no olefins and low aromatics. However, light hydrocrackate has poor octane characteristics which must be offset by some other component and also has high vapor pressure. California refiners distill their hydrocrackate somewhat differently than most refiners elsewhere but otherwise the materials are quite similar.

Reformates have no sulfur, no olefins, low vapor pressure and high octane, but have appreciable benzene and high aromatics. Reformates in most other regions have much higher concentrations of benzene than California reformates limiting their usefulness for CARBOB.

Desulfurized straight run gasoline has low benzene, no olefins and low sulfur but have relatively high vapor pressure and poor octane. In many areas straight run gasolines are not desulfurized and distillation characteristics may be different. California straight run gasolines tend to be slightly heavier than those elsewhere due to steps taken for benzene control in reformate.

FCC gasoline in California tends to be highly fractionated with some desulfurization available. FCC feed stocks tend to be hydrotreated and have quite low sulfur content limiting the sulfur content of raw FCC gasoline in California. Refiners elsewhere tend not to fractionate their FCC gasoline into as many components and almost never remove sulfur from the FCC gasoline itself.

Many refinery gasoline blend stocks found outside California are not practically usable to manufacture CARB gasoline. Conventional reformate has very high benzene content and high end point which severely limit how much of this material can be used in CARB

reformulated gasoline. Many FCC gasolines have very high sulfur content which would prevent them from being more than a few per cent of a CARB gasoline blend regardless of what other components were used. Such blend stocks are useful where they are produced because prevailing gasoline specifications in those areas are much less stringent than CARB specifications. Using such blend stocks for making CARBOB is possible but limited by the refiner's ability to find appropriate combinations of blend stocks such that all requirements are met.

Typical blend stocks available in refineries outside California were evaluated to determine the refiner's ability to produce CARB gasoline with those blend stocks. The blend stocks produced outside California are generally not designed to maximize CARB gasoline volume and are oriented toward other types of specifications. Suitability for producing CARB gasoline is more or less a coincidence for those blend stocks rather than a specific goal.

Some regions have more suitable blend stocks than others. For example, many USGC refiners produce EPA reformulated gasoline and will be complying with the more stringent EPA specifications to be in place after 2000. Hence such refiners already have taken steps to reduce contaminants such as benzene and sulfur. Refiners in other markets such as Latin America have not been called on to produce appreciable quantities of EPA or other reformulated gasoline. In some markets octane-enhancing compounds containing lead (TEL and TML) are still being phased out. In those markets benzene and sulfur limits tend to be much higher. Processing steps used in the U.S. to reduce air toxics have not been universally adopted and blend stocks in other areas can be much higher in objectionable compounds than those found in, for instance, the USGC.

5.3 IMPORTANT FEATURES OF CARB BLEND STOCKS

As described more completely in Section 7.3, possible blends of gasoline using blend stock qualities typical of each region were evaluated. The blends were evaluated using the predictive model to determine how well blend stocks from each region could be used to produce CARBOB. At this point in the analysis, these blend results were used to identify important characteristics of CARBOB that most limit blending opportunities and to identify key blend stocks and process units. Blend stock qualities were used with the assumption that no special control strategies were employed.

The most difficult features of CARBOB to meet will be low sulfur content and low vapor pressure. CARB sulfur limits are so low that many common gasoline streams could be used only in insignificant amounts without exceeding allowable levels. Refiners who are not equipped to thoroughly debutanize gasoline components may find it very difficult to manufacture CARB gasoline.

Sulfur control capability can be estimated by review of publicly available refinery configuration information and knowledge of the typical sulfur contents of various gasoline blend stocks. For each refinery, the capacity for naphtha desulfurization was compared to reformer capacity. Reformer feed stock must always be desulfurized but naphtha desulfurizers also can remove sulfur from light straight run gasoline that can be used for

CARBOB blending. Refineries with a high level of excess naphtha desulfurization are considered likely to have available low sulfur straight run gasoline while those without such capability would have only higher sulfur straight run gasoline. FCC gasoline desulfurization is an unusual process and is not well reported. It was assumed that refineries outside California could not desulfurize FCC gasoline. FCC gasoline sulfur levels were assumed to be related to the type of crude being processed. However, FCC gasoline sulfur levels are typically high enough to severely limit its use in CARBOB blends regardless of crude type.

There is no reliable way to estimate the debutanization capability of refineries from publicly available data sources. As a practical matter, all refineries have some ability to remove butane from gasoline blend stocks. The degree of such capability, that is the minimum vapor pressure to which any particular stream can be produced, cannot be deduced from publicly available statistical data. For purposes of this study it has been assumed that existing debutanization systems can be used to reduce gasoline blend stock vapor pressures to required levels, about 6-7 psia. This assumption is believed not to introduce appreciable overestimation of CARBOB capability.

Other CARBOB specification requirements, T50, T90, olefin, benzene, and aromatics, while difficult to meet if all of a refinery's gasoline is to be produced as CARB, can be readily handled by selected blending for a small part of gasoline production.

5.4 KEY PROCESS UNITS

The key process units contributing to an ability to produce CARB gasoline are considered to be alkylation, naphtha desulfurization, hydrocracking and aromatics extraction. Alkylate is the best blend stock for CARB as it has favorable characteristics on all counts and the alkylation process reduces objectionable olefins in other blend stocks. Naphtha desulfurization, in excess of the desulfurization of reformer feed stocks, is considered an important indicator of ability to control gasoline sulfur content and produces important light gasoline components substantially free of objectionable sulfur or olefins. Hydrocracking products also lack objectionable sulfur and olefins and light hydrocrackate is a suitable substitute for desulfurized light straight run gasoline in manufacturing CARBOB. Aromatics extraction can be used to remove excess aromatics from otherwise acceptable reformate which is low in sulfur and olefins. Aromatics raffinate has poor octane characteristics and relatively unattractive high boiling ranges but may be a useful adjunct to other available blend stocks.

Alkylation, naphtha desulfurization, hydrocracking and aromatics extraction are considered useful indicators of CARB gasoline manufacturing capability. Refiners lacking appreciable amounts of all these types of processing are considered unlikely candidates to be able to manufacture commercially significant quantities of CARB gasoline. Other types of refinery processing such as FCC, reforming and coking, are relevant to a refiner's ability to produce gasoline but are not key to producing CARBOB.

6. SCREENING CRITERIA

Two indexing systems were established to allow the review of capabilities of the world's refineries. The CARB Index is a relative measure of the presence of the types of processing associated with an ability to produce CARB gasoline. The Gasoline Production Index (GPI) is a broader measure of the presence of the types of processing associated with an ability to produce gasoline of any quality.

6.1 CARB INDEX

The CARB Index is a relative measure of the presence of the types of refinery process equipment associated with an ability to produce CARB gasoline. High CARB index does not assure that a refinery will be able to produce CARB gasoline. Some types of equipment needed to produce CARB gasoline such as sufficient storage and segregation capability are not reported and refineries vary in their other burdens and ability to make available for CARB blending high quality materials produced from CARB Index units. Similarly, a low CARB index does not necessarily preclude the facility from producing any CARB gasoline. Some facilities underreport capabilities and sometimes key blend stocks can be acquired from outside the refinery. The CARB Index is used to focus attention on the refineries with the greatest potential to produce CARB gasoline and to help characterize regional refining systems.

6.1.1 Index Components

Most world refineries that lack any alkylation will be unable to produce CARBOB. Alkylate provides a critical high octane component with no objectionable properties which can dilute benzene, aromatics and olefin from other blend stocks to acceptable levels. While it is technically possible to devise a processing scheme to produce CARBOB in refineries with no alkylation, such a scheme would require substantial steps in the direction of benzene control in reformate and other streams. These steps would not be done in the absence of a stringent benzene specification. In light of this situation, for refineries without any alkylation capacity, the CARB Index is defined as zero.

For refineries with at least some alkylation, the CARB Index is calculated by multiplying the reported capacity of each process unit, expressed in barrels per stream day by an index factor which is indicative of the importance or usefulness of that unit to producing CARB gasoline. Most process units have CARB Index factors of zero indicating that their contribution to producing CARB gasoline is not significant. Process units with non-zero CARB Index factors are shown below in Table 6.1.1-1.

TABLE 6.1.1-1
CARB INDEX FACTORS

Alkylation	1.0
Hydrocracking	0.4
Aromatics Extraction	0.3
LSR Naphtha Desulfurization	0.5

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6.1.2 Use of the Index

The CARB Index of every refinery in the world was calculated. Refineries were ranked according to their CARB Indices. Based on discussions with refiners and technical considerations a CARB Index of 10,000 was determined to be the minimum level likely to result in a commercially significant ability to produce CARB gasoline. All refineries outside California known to produce CARB gasoline were found to be above this level and no refinery outside of California with a CARB Index below 10,000 is known to have produced any CARB gasoline. Those refineries with a CARB Index at or above 10,000 were designated as “CARBOB-Capable” and those with a CARB Index below 10,000 were designated as “CARBOB-Incapable”.

6.2 GASOLINE PRODUCTION INDEX

Gasoline Production Index (GPI) is a measure of the presence of the types of process equipment used to produce gasoline. Because some refinery equipment has flexibility to produce various alternative products of which gasoline is only one, GPI is not an absolute measure of a refinery’s ability to produce gasoline. Furthermore, refiners may elect to sell gasoline precursors such as naphtha into alternative markets such as the petrochemicals feed stock market rather than devote them to manufacturing gasoline.

6.2.1 Index Components

A refinery’s GPI score is calculated by multiplying the reported capacity of each process unit expressed in barrels per stream day by its GPI factor, a number indicative of the typical usefulness of that type of processing for producing gasoline blend stocks. Many types of units, such as diesel fuel hydrotreaters, do not contribute meaningfully to the production of gasoline and are assigned GPI factors of zero.

Some process units are typically operated differently in various regions of the world. In the U.S. market, for example, gasoline is typically the key processing objective for refiners and FCC units operate to maximize gasoline production. In other markets, distillates are more important products and FCC units operate with less emphasis on gasoline. To reflect these differences, GPI factors were varied slightly from region to region. Non-zero GPI factors are shown on Table 6.2.1-1 below:

TABLE 6.2.1-1
GPI FACTORS

	Pacific North West	USGC	Carribean	Europe	Latin America	Middle East	Far East
Crude	0.25	0.21	0.10	0.15	0.12	0.12	0.10
Thermal Cracker	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Visbreaker	0.11	0.11	0.11	0.11	0.11	0.11	0.11
FCC	0.55	0.55	0.55	0.45	0.55	0.55	0.40
Hydrocracker	0.40	0.40	0.40	0.40	0.40	0.40	0.40
Alkylation	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Polymerization	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Aromatics	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Reforming	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Desulfurization, LSR	1.00	1.00	1.00	1.00	1.00	1.00	1.00

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6.2.2 Use of the Index

The GPI factors were used with approximate unit utilization factors to estimate the production of gasoline blend stocks of all types from the refineries in each region. The blend stock production figures were used in Section 8 along with an estimate of the fraction of alkylate production that could be devoted to CARBOB, to evaluate blending opportunities in the context of the predictive model.

7. REGIONAL CAPABILITY

In this section, the CARBOB-Capable refineries in each region are identified. Tables in this section include key process unit capacities for each refinery, its CARB Index score and its GPI score. CARB Index score is the determinant of whether a refinery is considered CARBOB-Capable or CARBOB-Incapable.

7.1 PACIFIC NORTH WEST

Table 7.1-1 shows the only five refineries active in the Pacific North West manufacturing gasoline of any type. A review of the configurations of the available refinery capacity suggests that although there is a reasonable potential to supply useful blend stocks, there is only limited potential to supply blended CARBOB.

The bulk of the refinery capacity in the Pacific North West is controlled by refiners with operations in California. These refiners are thought likely to operate their West Coast multi-refinery systems in integrated fashion in the event that supply shortfalls are triggered by any specification change such as an MTBE ban. An exchange of gasoline blend stocks is likely to be as practical in this situation as the provision of CARBOB and would offer more optimization opportunities.

Only one refinery, Shell Anacortes, was identified as CARBOB-Capable. It is believed that a relatively large fraction of the alkylate from that refinery might be released for CARBOB in part because of cross-optimization opportunities with other commonly-owned facilities on the West Coast.

7.2 U.S. GULF COAST

Twenty six coastal refineries were identified as being potentially capable of producing CARB gasoline as shown on Table 7.2-1. Of those twenty six, only one, Valero in Corpus Christi, was identified as clearly having been a supplier of CARB gasoline in the past. Ten of the CARBOB-Capable refineries are affiliated with California gasoline marketers. An additional three refineries were identified as potentially CARBOB-Capable but lack coastal access. These refineries, Phillips in Borger, Texas, and Diamond Shamrock in Sunray/ McKee and Three Rivers, are located in Central or West Texas and were dropped from further consideration.

USGC refineries serve many markets including not only the regional market but also the U.S. East Coast and markets in the Mid-Continent area. In the USGC refineries, gasoline is manufactured to a wide variety of specifications. EPA reformulated gasoline is routinely manufactured at all the sophisticated refineries on the USGC. Many of the refineries are able to produce low benzene reformate which is helpful to manufacturing CARBOB. None of the refineries are believed to possess FCC gasoline desulfurization capability though some sweet crudes are processed and FCC feed stocks may be desulfurized reducing FCC gasoline sulfur from high to moderate levels.

Because of their technical sophistication, petrochemical integration and the needs already to produce some reformulated fuels, the ability of the USGC refineries to produce CARBOB from a given volume of alkylate is equal or superior to all regions of the world other than California.

The volume of alkylate that can be released from USGC refineries is sensitive to whether the MTBE ban is extended nationwide or confined to California. In the event that the MTBE ban is confined to California, then about 20% of USGC alkylate might be released either for CARBOB blending or for direct sales as a blend stock. However, if the MTBE ban is extended nationwide, then burdens on the USGC system will be higher. In that event, we believe that the ability of the USGC refiners to divert alkylate will be cut approximately in half.

7.3 CARIBBEAN

One Caribbean refiner, Hess Oil Virgin Islands, has been identified as an historical supplier of CARB gasoline. One other refiner, Refineria Isla Curazao SA, was identified as a potential CARBOB-Capable refiner as shown in Table 7.3-1. Notwithstanding the substantial size of the Curacao refinery, import records suggest only very limited production of EPA-reformulated gasoline, no more than about 3,000 barrels per day, and few exports to the U.S. market. As a result, Curacao is not considered a likely supplier of CARB fuels.

The Hess Oil Virgin Islands facility is undergoing modifications as a result of a recent transaction between Hess' parent company and PDVSA, the Venezuelan national oil company. The ultimate influence of those modifications on CARBOB capacity cannot be identified at this time. Nevertheless, the reorientation of the refinery more toward heavy, high sulfur Venezuelan crude oils and the addition of more coker processing has the potential to trigger some deterioration in gasoline qualities important to CARBOB manufacturing.

Given the blend stocks that exist today, Hess is thought to possess an ability to transform alkylate into CARBOB similar to that of the Pacific North West region.

7.4 EUROPE

Europe has eighteen refineries which have been identified as potentially CARBOB-capable as shown on Table 7.4-1. One European refiner, Neste Oy in Porvoo, Finland, has actually manufactured CARB gasoline. The European refiners face a variety of different specifications at the moment but are entering a new phase of harmonized regulation.

Currently benzene specifications in Europe are loose by U.S. standards calling for a maximum of five percent in most countries. Some countries have adopted more stringent specifications and Italy, for example, is reducing benzene content by voluntary agreements with the oil companies to 1.4 percent in 1997 and 1 per cent by July 1999.

A program is underway which would harmonize European specifications and reduce emissions in a manner similar to the reformulated fuels programs in the U.S. The final determination has not been made as to what the specifications will be. Proposals call for reductions in sulfur, RVP, aromatics, benzene and olefins as well as an oxygen limit. Sulfur, currently about 300 ppm may fall to the 30-100 ppm range. RVP levels, currently about 68 kPa are proposed to fall to 58 kPa or about 8.4 psia. Proposals for aromatics content range from as low as 23 to as high as 37 per cent compared with an estimated current average value of 40 per cent. Benzene would be reduced from about 2.3 per cent to 0.7 to 2.3 per cent. Olefins would be reduced slightly from current 11 per cent levels to the 8 to 10 per cent range. It is possible that an entirely new proposal will be developed with more stringent requirements. Unlike the U.S. or CARB reformulated fuels programs, there is expected to be no flexibility such as is provided by the complex or predictive models. There may be a phased initiation of the program in various European countries.

Movement toward these reformulated programs in Europe is viewed as helpful to providing CARBOB for California. More European refiners will need to produce low benzene and low sulfur blend stocks for gasoline. The timing of the new programs is expected to be generally consistent with a possible MTBE ban.

7.5 LATIN AMERICA

Latin American refineries do not supply appreciable gasoline to the U.S. Only small amounts of the gasoline that is provided meets EPA reformulated specifications. Four Latin America refiners have been identified as potentially CARBOB-Capable on Table 7.5-1. Three of those refineries are in Venezuela and one is in Brazil.

Venezuela has been a modest supplier of EPA reformulated gasoline to East Coast markets. The Lagoven Judibana Falcon refinery, formerly known as Amuay, is a very large refinery at 571,000 barrels per day and has been the subject of considerable capital investment in recent years. Judibana is a coking refinery with a large alkylation unit. The Maraven Punta Cardon refinery and the Corpoven El Palito refinery are simpler than Judibana but both include appreciable alkylation capacity and score reasonably well on the CARB Index.

Latin American refineries suffer some shortcomings with respect to CARBOB manufacture. These refineries as a group lack sufficient desulfurization to produce appreciable low sulfur materials to combine with alkylate. Most naphtha desulfurization appears to be dedicated to producing reforming feed stocks with very little remaining to desulfurize straight run gasoline. Because of these problems, the ability of the Latin American refineries to transform their available alkylate into CARBOB is unusually poor.

7.6 MIDDLE EAST

The Middle East region includes only two refineries which were considered potentially CARBOB-Capable on Table 7.6-1. Generally, Middle East refineries use simple refining equipment processing sour crude oil to produce mostly distillates and residual fuel oils. As

a group the Middle East refiners are unable to produce high quality gasolines and a large volume of leaded fuels still is produced in the area. The two refineries that were identified as CARBOB-Capable were the Saudi Aramco-Mobil Yanbu refinery and the Bahrain Petroleum Company refinery at Awali. Those two refineries were the only two identified in the Middle East as possessing any alkylation capacity.

The two Middle East CARBOB-Capable refineries have some shortcomings with respect to CARBOB manufacture. Because the markets served by the refineries are generally not sensitive to benzene content, benzene levels in blend stocks are expected to be at relatively unconstrained levels. FCC gasoline sulfur content is expected to be relatively high because of the high sulfur content of the crudes found in the region and processed in the Saudi refineries.

The Middle East refineries have some helpful characteristics. Light low sulfur blend stocks available from hydrocrackers assist in meeting specifications and place the Middle East refineries in a superior position to those in Latin America.

7.7 FAR EAST

The Far East region includes sixteen refineries that were identified as potentially CARBOB-Capable. As shown in Table 7.7-1, five of these refineries were in China, five were in Japan, two were in Singapore and one each in Taiwan, South Korea, Australia and Indonesia. Most of the refineries in Asia lack any alkylation capacity, considered key to manufacturing commercial volumes of CARBOB. Furthermore, many refineries lack any sort of conversion equipment and are not effective gasoline producers at all.

Japan’s refineries are poorly equipped to manufacture CARB gasoline for export. Japanese refiners as a group export only small volumes and gasoline is exported very infrequently. Japanese refiners generally lack the ability to segregate special gasoline grades and there is no industry providing third party terminaling services in Japan. Cargo loading equipment is poor and is oriented toward very small coastal carriers used to supply the domestic market.

China has a large refining system though many facilities are plagued by logistical disadvantages. China consumes very large quantities of gasoline and is a net product importer. Nevertheless, there is a reasonable prospect that some of the indicated CARB capability could be translated into actual product shipments.

Singapore is a major source of produce exports to many Asian nations. Product loading facilities are excellent and the refineries as a group are accustomed to manufacturing many different product specifications.

Korea is a reasonable source of product exports. Korean refiners have been exporting appreciable products to regional markets and shipping distances to California are not excessive. The Yukong refinery is extremely large and includes hydrocracking, aromatics and alkylation capacity.

Far East refineries as a group are hampered principally by their poor ability to control benzene. Benzene reduction programs are only beginning in those Asian markets that have them at all.

TABLE 7.1-1
PACIFIC NORTH WEST
(Barrels per Stream Day)

Company	Location	State	Hydro-cracking	Alkylation	Aromatics	Excess Naphtha HDS	GPI Factors	CARB SCORE	CARB CAPABILITY
Shell Oil	Anacortes	WA	0	11,500	0	7,500	63,190	15,250	CAPABLE
Subtotal Capable			**0**	**11,500**	**0**	**7,500**	**63,190**	**15,250**	
Texaco	Anacortes	WA	0	8,550	0	450	74,877	8,775	INCAPABLE
Tosco	Ferndale	WA	0	6,000	0	500	41,875	6,250	INCAPABLE
ARCO	Ferndale	WA	50,000	0	0	0	79,680	0	INCAPABLE
U.S. Oil & Refining	Tacoma	WA	0	0	0	1,250	10,200	0	INCAPABLE
Subtotal Incapable			**50,000**	**14,550**	**0**	**2,200**	**206,632**	**15,025**	
TOTAL PACIFIC NORTH WEST			**50,000**	**26,050**	**0**	**9,700**	**269,822**	**30,275**	

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TABLE 7.2-1
U.S. GULF COAST
(Barrels per Stream Day)

Company	Location	State	Hydro-cracking	Alkylation	Aromatics	Excess Naphtha HDS	GPI Factors	CARB SCORE	CARB CAPABILITY
Amoco Oil	Texas City	TX	114,000	58,900	42,800	0	309,771	117,340	CAPABLE
Basis Petroleum, Inc.	Houston	TX	0	10,400	5,700	2,100	56,771	13,160	CAPABLE
BP Oil Co.	Belle Chasse	LA	0	34,200	21,150	5,400	140,108	43,245	CAPABLE
Chevron	Pascagoula	MS	58,000	14,800	15,100	0	147,380	42,530	CAPABLE
CITGO	Corpus Christi	TX	0	21,000	0	0	97,130	21,000	CAPABLE
CITGO	Lake Charles	LA	36,000	20,700	4,500	0	178,518	36,450	CAPABLE
Clark	Port Arthur	TX	0	15,500	9,800	0	94,940	18,440	CAPABLE
Coastal Ref. & Mkt.	Corpus Christi	TX	18,500	3,200	17,500	0	47,920	15,850	CAPABLE
Conoco	Lake Charles/Westlake	LA	26,600	10,400	0	1,900	113,220	21,990	CAPABLE
Crown Central	Houston	TX	0	11,700	0	0	62,445	11,700	CAPABLE
Deer Park Refining Limited Partnership	Deer Park	TX	62,600	16,500	17,900	0	141,966	46,910	CAPABLE
Diamond Shamrock	Sunray/McKee	TX	25,000	8,700	0	0	76,400	18,700	CAPABLE
Diamond Shamrock	Three Rivers	TX	25,000	6,000	0	4,000	43,800	18,000	CAPABLE
Exxon	Baton Rouge	LA	22,500	35,000	0	52,400	272,540	70,200	CAPABLE
Exxon	Baytown	TX	24,000	28,000	0	39,200	233,990	57,200	CAPABLE
Fina Oil & Chemical	Port Arthur	TX	0	5,500	13,000	6,500	76,535	12,650	CAPABLE
Koch Refining	Corpus Christi	TX	15,000	20,000	36,000	30,000	142,100	51,800	CAPABLE
Lyondell-CITGO	Houston	TX	0	20,900	13,700	8,000	133,240	29,010	CAPABLE
Marathon Oil	Garyville	LA	0	26,000	0	20,500	122,750	36,250	CAPABLE
Marathon Oil	Texas City	TX	0	10,000	2,500	0	42,300	10,750	CAPABLE
Mobil Oil	Beaumont	TX	50,000	12,200	0	0	162,590	32,200	CAPABLE
Mobil Oil	Chalmette	LA	20,000	12,000	9,600	0	97,138	22,880	CAPABLE
Murphy Oil	Meraux	LA	0	8,000	0	4,000	47,750	10,000	CAPABLE
Phillips 66 Co.	Borger	TX	0	17,500	0	0	74,050	17,500	CAPABLE
Phillips 66 Co.	Sweeny	TX	0	19,000	5,300	16,500	111,380	28,840	CAPABLE
Shell Oil	Norco	LA	35,000	15,000	0	0	138,590	29,000	CAPABLE
Star Enterprise	Convent	LA	45,000	13,050	0	1,800	129,513	31,950	CAPABLE
Star Enterprise	Port Arthur	TX	17,820	18,000	0	0	129,038	25,128	CAPABLE
Valero Refining Co.	Corpus Christi	TX	30,000	10,800	0	9,400	64,279	27,500	CAPABLE
	Subtotal Capable		**625,020**	**502,950**	**214,550**	**201,700**	**3,488,152**	**918,173**	

TABLE 7.2-1 (CONTINUED)
U.S. GULF COAST
(Barrels per Stream Day)

Company	Location	State	Hydro-cracking	Alkylation	Aromatics	Excess Naphtha HDS	GPI Factors	CARB SCORE	CARB CAPABILITY
AGE Refining & Manufacturing	San Antonio	TX	0	0	0	0	1,050	0	INCAPABLE
AIPC	Lake Charles	LA	0	0	0	0	5,796	0	INCAPABLE
Atlas Processing Co. Div of Pennzoil	Shreveport	LA	0	0	0	4,500	9,702	0	INCAPABLE
Basis Petroleum, Inc.	Krotz Springs	LA	0	0	0	3,100	38,376	0	INCAPABLE
Basis Petroleum, Inc.	Texas City	TX	0	5,700	0	2,900	59,490	7,150	INCAPABLE
Calcasieu Refining	Lake Charles	LA	0	0	0	0	2,940	0	INCAPABLE
Calumet	Princeton	LA	0	0	0	0	1,680	0	INCAPABLE
Calumet Lubricants Co.	Cotton Valley	LA	0	0	0	3,600	1,835	0	INCAPABLE
Canal Refining Co.	Church Point	LA	0	0	0	0	1,890	0	INCAPABLE
Chevron	El Paso	TX	0	8,200	0	0	42,932	8,200	INCAPABLE
Coastal Ref. & Mkt.	Mobile Bay	AL	0	0	0	0	3,150	0	INCAPABLE
Ergon Refining	Vicksburg	MS	0	0	0	0	5,250	0	INCAPABLE
Fina Oil & Chemical	Big Spring	TX	0	5,000	1,000	4,500	29,555	7,550	INCAPABLE
Giant Industries	Gallup	NM	0	1,800	0	0	10,843	1,800	INCAPABLE
Giant Refining Co.	Bloomfield	NM	0	0	0	0	8,460	0	INCAPABLE
Howell Hydrocarbons	Channelview	TX	0	0	0	0	504	0	INCAPABLE
Hunt Refining Co.	Tuscaloosa	AL	0	0	0	450	11,021	0	INCAPABLE
LaGloria Oil & Gas	Tyler	TX	0	4,200	0	3,500	25,167	5,950	INCAPABLE
Navajo Refining	Artesia	NM	0	9,400	0	0	32,175	9,400	INCAPABLE
NTPS	Corpus Christi	TX	0	0	0	0	6,300	0	INCAPABLE
Placid Refining	Port Allen	LA	0	3,800	0	0	24,330	3,800	INCAPABLE
Pride Refining	Abilene	TX	0	0	0	0	9,408	0	INCAPABLE
Shell Chemical Co.	St. Rose	LA	0	0	0	0	8,400	0	INCAPABLE
Shell Oil	Odessa	TX	0	3,200	0	3,700	14,423	5,050	INCAPABLE
Shell Oil Products Co.	Saraland	AL	0	0	0	5,000	15,960	0	INCAPABLE
Southland Oil	Lumberton	MS	0	0	0	0	1,218	0	INCAPABLE
Southland Oil	Sandersville	MS	0	0	0	0	2,310	0	INCAPABLE
	Subtotal Incapable		**0**	**41,300**	**1,000**	**31,250**	**374,166**	**48,900**	
	TOTAL USGC		**625,020**	**544,250**	**215,550**	**232,950**	**3,862,317**	**967,073**	

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TABLE 7.3-1
CARIBBEAN
(Barrels per Stream Day)

Country	Company	Location	Hydro-cracking	Alkylation	Aromatics	Excess Naphtha HDS	GPI Factors	CARB SCORE	CARB CAPABILITY
Netherlands Antilles	Refineria Isla Curazao SA	Emmastad	0	8,020	0	33,000	76,520	24,520	CAPABLE
Virgin Islands	Hess Oil Virgin Islands Corp.	St. Croix	0	14,000	30,000	0	152,050	23,000	CAPABLE
	Subtotal Capable		**0**	**22,020**	**30,000**	**33,000**	**228,570**	**47,520**	
Aruba	Coastal Aruba Refining Co. N.V.	San Nicolas	38,000	0	0	0	45,402	0	INCAPABLE
Barbados	Mobil Oil Barbados Ltd.	Bridgetown	0	0	0	0	720	0	INCAPABLE
Cuba	Government	Nico Lopez, Havana	0	0	0	250	22,701	0	INCAPABLE
Cuba	Government	Cabaiguan	0	0	0	0	252	0	INCAPABLE
Cuba	Government	Santiago de Cuba	0	0	0	200	12,180	0	INCAPABLE
Cuba	Government	Cienfuegos	0	0	0	200	9,120	0	INCAPABLE
Dominican Republic	Falconbridge Dominicana C por A	La Bonao	0	0	0	6,200	1,920	0	INCAPABLE
Dominican Republic	Refineria Dominicana de Petroleo SA	Haina	0	0	0	0	4,080	0	INCAPABLE
Jamaica	Petrojam Ltd.	Kingston	0	0	0	2,860	3,550	0	INCAPABLE
Martinique	Ste. Anonyme de la Raffinerie des Antilles	Fort-de-France	0	0	0	6,200	1,600	0	INCAPABLE
Puerto Rico	Puerto Rico Sun Oil Co.	Yabucoa	15,600	0	0	0	14,740	0	INCAPABLE
Trinidad	Trinidad and Tobago Oil CL	Pointe-a-Pierre	0	1,200	1,700	0	33,650	1,710	INCAPABLE
	Subtotal Incapable		**53,600**	**1,200**	**1,700**	**15,910**	**149,915**	**1,710**	
	TOTAL CARIBBEAN		**53,600**	**23,220**	**31,700**	**48,910**	**378,485**	**49,230**	

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TABLE 7.4-1
EUROPE
(Barrels per Stream Day)

Country	Company	Location	Hydro-Cracking	Alkylation	Aromatics	Excess Naphtha HDS	GPI Factors	CARB SCORE	CARB CAPABILITY
Belgium	Esso Belgium	Antwerp	0	6,815	0	26,060	58,700	19,845	CAPABLE
Belgium	Fina Raffinaderij Antwerpen-	Antwerp	0	6,700	0	52,600	91,150	33,000	CAPABLE
Finland	Neste Oy	Porvoo	16,000	4,200	0	51,000	57,630	36,100	CAPABLE
France	Elf France	Donges	0	4,300	0	13,580	62,347	11,090	CAPABLE
Germany	Leune-Werke AG	Leuna	40,000	6,000	0	7,000	39,420	25,500	CAPABLE
Germany	Mineraloel Oberrhein	Karlsruhe	0	10,200	0	30,500	110,985	25,450	CAPABLE
Italy	Agip Raffinazione	Sannazzaro, Pavia	30,000	3,200	0	10,300	64,020	20,350	CAPABLE
Italy	Raffineria Mediterranea SrL	Milazzo	50,000	5,000	0	7,500	71,050	28,750	CAPABLE
Italy	Raffineria Siciliana Srl	Gela	0	10,000	6,700	2,650	49,600	13,335	CAPABLE
Italy	Saras SpA	Sarroch	50,000	6,800	0	0	110,500	26,800	CAPABLE
Netherlands	Netherlands Refining Co. NV	Europort & Pernis	0	5,850	0	42,300	96,183	27,000	CAPABLE
Netherlands	Shell Nederland Raffinaderij BV	Pernis	22,000	6,800	0	104,000	115,800	67,600	CAPABLE
United Kingdom	BP Refinery Grangemouth Ltd.	Grangemouth	31,500	4,500	1,000	22,500	54,818	28,650	CAPABLE
United Kingdom	Conoco Ltd.	South Killingholme	0	14,000	4,500	0	91,600	15,350	CAPABLE
United Kingdom	Elf Oil Ltd.	Milford Haven	0	6,400	0	7,500	39,025	10,150	CAPABLE
United Kingdom	Lindsey Oil Refinery Ltd.	Killingholm South Humberside	0	6,300	0	18,200	61,937	15,400	CAPABLE
United Kingdom	Mobil Oil CL	Coryton Essex	0	18,000	0	46,400	68,963	41,200	CAPABLE
United Kingdom	Pembroke Cracking Co.[1]	Milford Haven	0	33,000	0	29,000	73,500	47,500	CAPABLE
United Kingdom	Shell U.K. Ltd.	Stanlow	0	11,000	9,000	14,000	83,150	20,700	CAPABLE
		Subtotal Capable	**239,500**	**169,065**	**21,200**	**485,090**	**1,400,377**	**513,770**	
Austria	OeMV	Schwechat	0	0	0	17,500	45,101	0	INCAPABLE
Belgium	Belgian Refining Corp. NV	Antwerp	0	0	0	9,900	14,122	0	INCAPABLE
Belgium	Nynas Petroleum NV	Antwerp	0	0	0	0	2,250	0	INCAPABLE
Denmark	AS Dansk Shell	Fredericia	0	0	0	9,600	16,815	0	INCAPABLE
Denmark	Dansk Statoil AS	Kalundborg	0	0	0	0	16,280	0	INCAPABLE
Denmark	Kuwait Petroleum Refining (Danmark) A/S	Gulfhavn (Skaelskoer)	0	0	0	12,200	13,741	0	INCAPABLE
Finland	Neste Oy	Naantali	0	0	0	0	13,451	0	INCAPABLE
France	Cie. de Raffinage et de Distribution Total France	La Mede	0	3,000	0	0	37,420	3,000	INCAPABLE
France	Cie. de Raffinage et de Distribution Total France	Gonfreville L'Orcher	0	0	0	26,600	77,190	0	INCAPABLE
France	Cie. de Raffinage et de Distribution Total France	Mardyck	0	0	0	2,000	33,450	0	INCAPABLE
France	Cie. Rhenane de Raffinage	Reichstett-Vendenheim	0	0	0	8,100	21,310	0	INCAPABLE
France	Elf France	Grandpuits	0	3,150	0	13,060	33,309	9,680	INCAPABLE
France	Elf France	Feyzin	0	3,500	2,200	4,990	35,673	6,655	INCAPABLE
France	Esso SAF	Port Jerome	0	5,900	0	700	42,575	6,250	INCAPABLE
France	Esso SAF	Fos sur Mer	0	0	0	71,000	28,800	0	INCAPABLE
France	Mobil Oil Francaise	Notre Dame de Gravenchon	0	0	0	2,700	9,548	0	INCAPABLE
France	Shell Francaise	Berre l'Etang	0	0	0	18,000	34,350	0	INCAPABLE
France	Shell Francaise	Petit Couronne	0	0	0	20,000	31,470	0	INCAPABLE
France	Ste. Francaise des Petroles BP	Lavera	15,300	0	6,600	13,500	50,976	0	INCAPABLE

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TABLE 7.4-1 (CONTINUED)
EUROPE
(Barrels per Stream Day)

Country	Company	Location	Hydro-Cracking	Alkylation	Aromatics	Excess Naphtha HDS	GPI Factors	CARB SCORE	CARB CAPABILITY
Germany	BETA	Wihelmshaven	0	0	0	28,700	27,000	0	INCAPABLE
Germany	BP/AGIP	Vohburg/Ingolstadt	0	0	0	36,900	35,755	0	INCAPABLE
Germany	DEA Mineraloel AG	Wesseling	40,000	0	7,600	6,100	38,860	0	INCAPABLE
Germany	DEA Mineraloel AG	Heide	0	0	5,800	5,000	20,740	0	INCAPABLE
Germany	Deutsche Shell AG	Godorf	36,000	0	17,000	48,000	46,070	0	INCAPABLE
Germany	Deutsche Shell AG	Harburg-Grasbrook	0	0	0	14,000	23,660	0	INCAPABLE
Germany	Erdoel Raffinerie Neustadt GmbH	Neustadt-Donau	0	0	0	6,300	33,560	0	INCAPABLE
Germany	Esso AG	Ingolstadt	0	0	0	13,400	28,125	0	INCAPABLE
Germany	Holburn Europa Raffinerie GmbH	Harburg	0	0	0	20,500	20,138	0	INCAPABLE
Germany	OMV Mineralol Petrochemie	Burghausen	0	0	2,300	0	15,750	0	INCAPABLE
Germany	PCK Schwedt AG	Schwedt	0	6,100	5,000	0	66,498	7,600	INCAPABLE
Germany	Ruhr Oel GmbH	Gelsenkirchen	30,000	0	3,650	4,000	62,300	0	INCAPABLE
Germany	Schmierstoff Raffinerie	Salzbergen	0	0	0	0	465	0	INCAPABLE
Germany	Wintershall AG	Lingen	23,000	0	4,674	0	24,440	0	INCAPABLE
Greece	Hellenic Aspropyrgos Refinery SA	Aspropyrgos	0	0	0	5,200	44,154	0	INCAPABLE
Greece	Motor Oil (Hellas) Corinth Refineries SA	Aghii Theodori	0	2,400	0	6,600	35,142	5,700	INCAPABLE
Greece	Petrola Hellas SA	Elefsis	0	0	0	0	16,200	0	INCAPABLE
Greece	Thessaloniki Refining Co. AE	Thessaloniki	0	0	0	8,400	9,975	0	INCAPABLE
Ireland	Irish Refining Petroleum Corp. Ltd.	Whitegate	0	0	0	1,650	9,750	0	INCAPABLE
Italy	Agip Plus SpA	Livorno	0	0	0	10,000	12,600	0	INCAPABLE
Italy	Agip Raffinazione	Taranto	16,000	0	0	7,000	31,198	0	INCAPABLE
Italy	Agip Raffinazione	Porto Marghera	0	0	0	1,000	19,020	0	INCAPABLE
Italy	Anonima Petroli Italiana	Falconara, Marittima	0	0	0	2,900	19,394	0	INCAPABLE
Italy	Arcola Petrolifera SpA	La Spezia	0	0	0	0	4,950	0	INCAPABLE
Italy	ENI	Priolo	0	4,000	12,000	0	54,150	7,600	INCAPABLE
Italy	Esso Italiana SpA	Augusta, Siracusa	0	7,900	0	500	54,715	8,150	INCAPABLE
Italy	Iplom SpA	Busalla	0	0	0	0	6,975	0	INCAPABLE
Italy	Isab	Priolo Gargallo Melilli	65,000	0	0	26,000	76,100	0	INCAPABLE
Italy	Italiana Energia E Servizi SpA	Frassino, Mantova	0	0	0	7,125	12,306	0	INCAPABLE
Italy	Raffineria di Roma SpA	Rome	0	0	0	6,700	15,701	0	INCAPABLE
Italy	Sarpom	S. Martino Di Trecate	0	0	0	40,500	51,640	0	INCAPABLE
Italy	Tamoil Italia SpA	Cremona	0	0	0	12,800	17,130	0	INCAPABLE
Netherlands	Esso Nederland BV	Rotterdam	33,850	0	12,000	10,660	47,139	0	INCAPABLE
Netherlands	Kuwait Petroleum Europoort BV	Rotterdam	0	0	0	18,600	14,953	0	INCAPABLE
Netherlands	Smid & Hollander Raffinaderij BV	Amsterdam	0	0	0	0	1,500	0	INCAPABLE
Netherlands	Total Raffinaderij Nederland NV	Vlissingen	39,000	0	0	0	37,800	0	INCAPABLE
Norway	Esso Norge AS	Slagen-Valloy	0	0	0	10,500	18,322	0	INCAPABLE
Norway	Norske Shell AS	Sola	0	0	0	6,500	13,350	0	INCAPABLE
Norway	Rafinor AS	Mongstad	0	0	0	400	60,700	0	INCAPABLE

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TABLE 7.4-1 (CONTINUED)
EUROPE
(Barrels per Stream Day)

Country	Company	Location	Hydro-Cracking	Alkylation	Aromatics	Excess Naphtha HDS	GPI Factors	CARB SCORE	CARB CAPABILITY
Portugal	Petrogal	Sines	0	5,400	0	6,300	54,083	8,550	INCAPABLE
Portugal	Petrogal	Leca da Palmeira Porto	0	0	6,282	16,789	13,692	0	INCAPABLE
Spain	Asfaltos Espanoles SA	Tarragona	0	0	0	0	3,150	0	INCAPABLE
Spain	Cia. Espanola de Petroles	San Roque (Cadiz)	0	5,000	13,100	0	57,270	8,930	INCAPABLE
Spain	Cia. Espanola de Petroles	La Rabida Huelva	0	0	2,420	0	24,200	0	INCAPABLE
Spain	Cia. Espanola de Petroles	Tenerife	0	0	0	0	17,200	0	INCAPABLE
Spain	Petroleos del Mediterraneo	Castellon de la Plana	0	0	0	11,700	25,373	0	INCAPABLE
Spain	Petronor SA	Somorrostro Vizcaya	0	4,496	0	10,350	57,824	9,671	INCAPABLE
Spain	Repsol Petroleo SA	Puertollano, Ciudad Real	0	3,300	1,800	0	39,930	3,840	INCAPABLE
Spain	Repsol Petroleo SA	Tarragona	15,000	0	0	0	36,300	0	INCAPABLE
Spain	Repsol Petroleo SA	La Coruna	0	0	0	0	36,820	0	INCAPABLE
Spain	Repsol Petroleo SA	Cartagena Murcia	0	0	0	4,000	18,000	0	INCAPABLE
Sweden	AB Nynas Petroleum	Gothenburg	0	0	0	0	1,875	0	INCAPABLE
Sweden	AB Nynas Petroleum	Nynashamn	0	0	0	0	4,200	0	INCAPABLE
Sweden	OK Petroleum	Gothenburg	0	0	0	0	15,900	0	INCAPABLE
Sweden	Shell Raffinaderi BV	Gothenburg	0	0	0	11,000	19,650	0	INCAPABLE
Sweden	Skandinaviska Raffinaderi AB	Brofjorden-Lysekil	48,600	0	0	62,100	70,383	0	INCAPABLE
Switzerland	Raffinerie de Cressier SA	Cressier	0	0	0	11,000	13,290	0	INCAPABLE
Switzerland	Raffinerie du Sud-Ouest SA	Collombey	0	0	0	6,700	10,800	0	INCAPABLE
Turkey	Anadolu Tasfiyehanesi AS	Mersin	0	0	5,800	7,200	14,250	0	INCAPABLE
Turkey	Turkish Petroleum Refineries Corp.	Izmit	23,000	0	0	13,310	57,130	0	INCAPABLE
Turkey	Turkish Petroleum Refineries Corp.	Aliaga-Izmir	16,500	0	0	12,830	49,517	0	INCAPABLE
Turkey	Turkish Petroleum Refineries Corp.	Kirkkale	14,500	0	0	0	22,783	0	INCAPABLE
Turkey	Turkish Petroleum Refineries Corp.	Batman, Siirt	0	0	0	0	4,718	0	INCAPABLE
United Kingdom	Eastham Refinery Ltd.	Eastham, Cheshire	0	0	0	0	3,300	0	INCAPABLE
United Kingdom	Esso Petroleum CL	Fawley	0	0	0	33,800	95,569	0	INCAPABLE
United Kingdom	Gulf Oil GB	Milford Haven	0	0	0	13,100	16,800	0	INCAPABLE
United Kingdom	Nynas	Dundee	0	0	0	0	1,536	0	INCAPABLE
United Kingdom	Phillips Imperial Petroleum Ltd.	Port Clarence	0	0	0	0	15,000	0	INCAPABLE
United Kingdom	Shell U.K. Ltd.	Shell Haven	24,000	0	0	26,000	23,400	0	INCAPABLE
United Kingdom	Texaco Ltd.	Pembroke, Dyfed	0	0	0	0	29,860	0	INCAPABLE
		Subtotal Incapable	**439,750**	**54,146**	**108,226**	**841,964**	**2,539,857**	**85,626**	
		TOTAL EUROPE	**679,250**	**223,211**	**129,426**	**1,327,054**	**3,940,234**	**599,396**	

Note: 65% Texaco 35% Gulf Oil GB

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TABLE 7.5-1
LATIN AMERICA
(Barrels per Stream Day)

Country	Company	Location	Hydro-Cracking	Alkylation	Aromatics	Excess Naphtha HDS	GPI Factors	CARB SCORE	CARB CAPABILITY
Brazil	President Bernardes (RPBC)	Cubatao, Sao Paulo	0	3,140	7,550	11,320	54,956	11,065	CAPABLE
Mexico	Pemex	Salina Cruz	0	14,100	0	11,000	103,200	19,600	CAPABLE
Venezuela	Corpoven	El Palito Carabobo	0	20,000	3,500	0	62,400	21,050	CAPABLE
Venezuela	Lagoven	Judibana Falcon	0	17,800	0	0	149,158	17,800	CAPABLE
Venezuela	Maraven	Punta Cardon Falcon	0	28,800	0	7,000	127,705	32,300	CAPABLE
		Subtotal Capable	**0**	**83,840**	**11,050**	**29,320**	**497,419**	**101,815**	
Argentina	Destileria Argentina de Petroleo SA	Lomas de Zamora	0	0	0	0	960	0	INCAPABLE
Argentina	Esso SAPA	Campana	0	0	0	5,400	30,087	0	INCAPABLE
Argentina	Esso SAPA	Puerto Galvan	0	0	0	0	4,560	0	INCAPABLE
Argentina	Isaura SA	Bahia Blanca	0	0	0	2,547	7,743	0	INCAPABLE
Argentina	Shell Cia. Argentina de Petroleo SA	Dock Sud	0	1,700	0	300	34,943	1,850	INCAPABLE
Argentina	Sol Petroleo SA	San Francisco Solana, Quillmes	0	0	0	0	720	0	INCAPABLE
Argentina	YPF	Lujan de Cuyo	26,000	0	0	0	55,721	0	INCAPABLE
Argentina	YPF	La Plata	0	0	0	0	68,620	0	INCAPABLE
Argentina	YPF	Plaza Huincul	0	0	0	0	2,832	0	INCAPABLE
Argentina	YPF	Campo Duran	0	0	0	0	3,840	0	INCAPABLE
Argentina	YPF	Dock Sud	0	0	0	0	480	0	INCAPABLE
Argentina	YPF	San Lorenzo	0	0	0	0	6,937	0	INCAPABLE
Bolivia	YPFB	Cochabamba	0	0	0	0	3,107	0	INCAPABLE
Bolivia	YPFB	Santa Cruz	0	0	0	0	2,280	0	INCAPABLE
Bolivia	YPFB	Sucre	0	0	0	0	360	0	INCAPABLE
Brazil	REFAP	Canoas, Rio Grande do Sul	0	0	0	0	15,910	0	INCAPABLE
Brazil	REFCAP	Maua Santo Andre, Sao Paulo	0	0	0	0	10,941	0	INCAPABLE
Brazil	DRGP	Rio Grande do Sul	0	0	0	0	3,150	0	INCAPABLE
Brazil	REDUC	Duque de Caxias, Rio de Janeiro	0	0	0	11,320	52,665	0	INCAPABLE
Brazil	REGAP	Betim, Minas Gerais	0	0	0	11,320	34,570	0	INCAPABLE
Brazil	REVAP	Sao Jose dos Campos, Sao Paulo	0	0	0	17,640	56,409	0	INCAPABLE
Brazil	RLAM	Mataripe, Bahia	0	0	0	0	27,801	0	INCAPABLE
Brazil	REMAN	Manaus, Amazonas	0	0	0	0	2,438	0	INCAPABLE
Brazil	REPLAN	Paulinia, Sao Paulo	0	0	0	0	60,424	0	INCAPABLE
Brazil	REPAR	Araucaria, Parana	0	0	0	0	44,240	0	INCAPABLE
Brazil	RPM	Rio de Janeiro	0	0	0	0	3,131	0	INCAPABLE
Chile	ENAP	Gregorio-Magallanes	0	0	0	0	1,158	0	INCAPABLE
Chile	Petrox SA	Talcahuano	0	0	0	0	24,593	0	INCAPABLE
Chile	Refineria de Concon	Concon	12,580	1,100	0	2,000	30,734	7,132	INCAPABLE

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TABLE 7.5-1 (CONTINUED)
LATIN AMERICA
(Barrels per Stream Day)

Country	Company	Location	Hydro-Cracking	Alkylation	Aromatics	Excess Naphtha HDS	GPI Factors	CARB SCORE	CARB CAPABILITY
Colombia	Empresa Colombiana de Petroleos	Barrancabermeja-Santander	0	2,100	1,600	0	61,690	2,580	INCAPABLE
Colombia	Empresa Colombiana de Petroleos	Cartagena, Bolivar	0	0	0	0	26,890	0	INCAPABLE
Colombia	Empresa Colombiana de Petroleos	Orito, Putumayo	0	0	0	0	216	0	INCAPABLE
Colombia	Empresa Colombiana de Petroleos	Tibu, N. de Santander	0	0	0	0	216	0	INCAPABLE
Colombia	Empresa Colombiana de Petroleos	Apiay	0	0	0	0	270	0	INCAPABLE
Costa Rica	RCP	Limon	0	0	0	0	3,750	0	INCAPABLE
Ecuador	Petroecuador	Esmeraldas	0	0	0	0	13,572	0	INCAPABLE
Ecuador	Petroecuador	Sta. Elena Peninsula	0	0	0	0	5,640	0	INCAPABLE
Ecuador	Petroecuador	Refineria Amazonas	0	0	0	0	2,400	0	INCAPABLE
Ecuador	Petroecuador	Lago-Agrio	0	0	0	0	120	0	INCAPABLE
El Salvador	Refineria Petrolera Acajutla SA	Acajutla	0	0	0	3,700	2,460	0	INCAPABLE
Guatemala	Basic Resources International	Peten	0	0	0	0	480	0	INCAPABLE
Guatemala	Texas Petroleum Co.	Escuintla	0	0	0	0	1,920	0	INCAPABLE
Honduras	Refineria Texas de Honduras SA	Puerto Cortes	0	0	0	1,200	1,680	0	INCAPABLE
Mexico	Pemex	Ciudad Madero	0	3,420	0	0	53,150	3,420	INCAPABLE
Mexico	Pemex	Salamanca	18,500	0	0	13,540	69,640	0	INCAPABLE
Mexico	Pemex	Minatitlan	0	0	17,150	4,000	46,600	0	INCAPABLE
Mexico	Pemex	Cadereyta	0	0	0	16,000	55,700	0	INCAPABLE
Mexico	Pemex	Tula Hidalgo	0	0	0	7,000	86,910	0	INCAPABLE
Nicaragua	Esso Standard Oil SA Ltd.	Managua	0	0	0	1,500	1,980	0	INCAPABLE
Panama	Refineria Panama SA	Las Minas	0	0	0	0	10,170	0	INCAPABLE
Paraguay	Petroleos Paraguayos	Villa Elisa	0	0	0	0	900	0	INCAPABLE
Peru	ANC	Talara	0	0	0	0	16,570	0	INCAPABLE
Peru	Maples Gas	Pucallpa	0	0	0	0	390	0	INCAPABLE
Peru	Petroleos del Peru	La Pampilla Lima	0	0	0	0	15,685	0	INCAPABLE
Peru	Petroleos del Peru	Conchan/Lima	0	0	0	0	780	0	INCAPABLE
Peru	Petroleos del Peru	Iquitos Loreto	0	0	0	0	1,260	0	INCAPABLE
Peru	Petroleos del Peru	Marsella Loreto	0	0	0	0	0	0	INCAPABLE
Uruguay	ANC	La Teja Montevideo	0	0	0	0	10,520	0	INCAPABLE
Venezuela	Corpoven	Puerto La Cruz Anzoategui	0	4,100	0	0	34,650	4,100	INCAPABLE
Venezuela	Corpoven	El Toreno Barinas	0	0	0	0	576	0	INCAPABLE
Venezuela	Corpoven	San Roque, Anzoategui	0	0	0	0	624	0	INCAPABLE
		Subtotal Incapable	**57,080**	**12,420**	**18,750**	**97,467**	**1,118,763**	**19,082**	
		TOTAL LATIN AMERICA	**57,080**	**96,260**	**29,800**	**126,787**	**1,616,182**	**120,897**	

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TABLE 7.6-1
MIDDLE EAST
(Barrels per Stream Day)

Country	Company	Location	Hydro-Cracking	Alkylation	Aromatics	Excess Naphtha HDS	GPI Factors	CARB SCORE	CARB CAPABILITY
Bahrain	Bahrain Petroleum Co.	Awali	48,600	3,060	0	900	78,517	22,950	CAPABLE
Saudi Arabia	Saudi Aramco-Mobil	Yanbu	40,000	23,500	0	26,800	134,205	52,900	CAPABLE
		Subtotal Capable	**88,600**	**26,560**	**0**	**27,700**	**212,722**	**75,850**	
Abu Dhabi	Abu Dhabi National Oil Co.	Ruwais	26,730	0	0	3,240	26,538	0	INCAPABLE
Abu Dhabi	Abu Dhabi National Oil Co.	Umm Al-Nar	0	0	0	23,310	9,690	0	INCAPABLE
Cyprus	Cyprus Petroleum Refinery Ltd.	Larnaca	0	0	0	0	3,120	0	INCAPABLE
Fujairah	Metro Oil Corporation	Fujairah	0	0	0	0	4,200	0	INCAPABLE
Iran	National Iranian Oil Co.	Tehran	57,200	0	0	0	53,730	0	INCAPABLE
Iran	National Iranian Oil Co.	Isfahan	30,000	0	0	0	47,980	0	INCAPABLE
Iran	National Iranian Oil Co.	Arak	24,500	0	0	0	30,803	0	INCAPABLE
Iran	National Iranian Oil Co.	Tabriz	18,000	0	0	0	22,455	0	INCAPABLE
Iran	National Iranian Oil Co.	Shiraz	9,280	0	0	0	9,502	0	INCAPABLE
Iran	National Iranian Oil Co.	Abadan	0	0	0	0	64,500	0	INCAPABLE
Iran	National Iranian Oil Co.	Lavan	0	0	0	0	2,400	0	INCAPABLE
Iran	National Iranian Oil Co.	Kermanshah (Bakhtaran)	0	0	0	0	3,600	0	INCAPABLE
Iraq	Ministry of Oil, Refinery Admin.	Baiji, North	38,000	0	4,000	0	33,200	0	INCAPABLE
Iraq	Ministry of Oil, Refinery Admin.	Dorah	0	0	0	0	11,040	0	INCAPABLE
Iraq	Ministry of Oil, Refinery Admin.	Basrah	0	0	0	0	15,120	0	INCAPABLE
Iraq	Ministry of Oil, Refinery Admin.	Haditha	0	0	0	0	840	0	INCAPABLE
Iraq	Ministry of Oil, Refinery Admin.	Khanaqin	0	0	0	0	1,440	0	INCAPABLE
Iraq	Ministry of Oil, Refinery Admin.	Nassiriyah	0	0	0	0	3,240	0	INCAPABLE
Iraq	Ministry of Oil, Refinery Admin.	Qayyarah	0	0	0	0	1,500	0	INCAPABLE
Iraq	Ministry of Oil, Refinery Admin.	Kirkuk	0	0	0	0	3,240	0	INCAPABLE
Iraq	Ministry of Oil, Refinery Admin.	Baiji, Sulahuddin	0	0	0	0	16,800	0	INCAPABLE
Iraq	Ministry of Oil, Refinery Admin.	Al Jezira	0	0	0	0	2,400	0	INCAPABLE
Iraq	Ministry of Oil, Refinery Admin.	Al Syniya	0	0	0	0	2,400	0	INCAPABLE
Iraq	Ministry of Oil, Refinery Admin.	Kasek	0	0	0	0	2,400	0	INCAPABLE
Israel	Oil Refineries Ltd.	Haifa	0	0	5,000	1,000	34,410	0	INCAPABLE
Israel	Oil Refineries Ltd.	Ashdod	0	0	0	8,500	28,675	0	INCAPABLE
Jordan	Jordan Petroleum Refinery	Zarqa	4,230	0	0	5,760	16,085	0	INCAPABLE

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TABLE 7.6-1 (CONTINUED)
MIDDLE EAST
(Barrels per Stream Day)

Country	Company	Location	Hydro-Cracking	Alkylation	Aromatics	Excess Naphtha HDS	GPI Factors	CARB SCORE	CARB CAPABILITY
Kuwait	Kuwait National Petroleum Co.	Shuaiba	82,000	0	0	11,000	51,280	0	INCAPABLE
Kuwait	Kuwait National Petroleum Co.	Mina Abdulla	38,000	0	0	7,200	56,600	0	INCAPABLE
Kuwait	Kuwait National Petroleum Co.	Mina Al-Ahmadi	36,000	0	0	2,000	79,600	0	INCAPABLE
Neutral Zone	Arabian Oil CL	Al Khafji	0	0	0	0	3,600	0	INCAPABLE
Oman	Oman Refinery Co.	Mina Al Fahal	0	0	0	4,000	10,200	0	INCAPABLE
Qatar	QGPC	Umm Saeed	0	0	0	8,000	6,900	0	INCAPABLE
Saudi Arabia	Arabian Oil Co. Ltd.	Ras Al Khafji	0	0	0	0	3,600	0	INCAPABLE
Saudi Arabia	Jeddah Refining Company	Jeddah	10,000	0	0	0	20,990	0	INCAPABLE
Saudi Arabia	Saudi Aramco	Riyadh	33,820	0	0	0	30,328	0	INCAPABLE
Saudi Arabia	Saudi Aramco	Ras Tanura	0	0	0	0	36,000	0	INCAPABLE
Saudi Arabia	Saudi Aramco	Yanbu	0	0	0	0	22,800	0	INCAPABLE
Saudi Arabia	Saudi Aramco	Rabigh	0	0	0	0	34,800	0	INCAPABLE
Saudi Arabia	Saudi Aramco-Shell	Jubail	44,000	0	5,800	61,000	56,160	0	INCAPABLE
Syria	Banias Refining Co.	Banias	25,000	0	0	0	28,950	0	INCAPABLE
Syria	Homs Refinery Co.	Homs	0	0	0	9,611	16,934	0	INCAPABLE
Yemen	Aden Refinery Co.	Aden	0	0	0	0	13,200	0	INCAPABLE
Yemen	Ministry of Oil and Mineral Resources	Marib	0	0	0	0	1,200	0	INCAPABLE
		Subtotal Incapable	**476,760**	**0**	**14,800**	**144,621**	**924,449**	**0**	
		TOTAL MIDDLE EAST	**565,360**	**26,560**	**14,800**	**172,321**	**1,137,171**	**75,850**	

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TABLE 7.7-1
FAR EAST
(Barrels per Stream Day)

Country	Company	Location	Hydro-Cracking	Alkylation	Aromatics	Excess Naphtha HDS	GPI Factors	CARB SCORE	CARB CAPABILITY
Australia	Ampol Refineries (NSW) Pty. Ltd.	Kurnell	0	7,800	0	17,500	43,625	16,550	CAPABLE
China	Baling Petrochemical	Baling	9,000	2,000	0	22,000	37,801	16,600	CAPABLE
China	Dalian Petrochemical	Dalian	20,000	2,000	0	3,000	52,258	11,500	CAPABLE
China	Maoming Petrochemical	Maoming	16,000	1,000	1,000	13,000	43,030	14,200	CAPABLE
China	Qilu Petrochemical	Qilu	42,000	3,000	0	19,000	57,146	29,300	CAPABLE
China	Shanghai Petrochemical	Jinshan	18,000	2,400	4,400	0	20,244	10,920	CAPABLE
Indonesia	Pertamina	Musi	0	16,200	0	0	39,586	16,200	CAPABLE
Japan	Idemitsu Kosan CL	Chita, Aichi	0	9,000	0	7,200	46,600	12,600	CAPABLE
Japan	Japan Energy	Mizushima	0	7,200	0	18,100	41,804	16,250	CAPABLE
Japan	Mitsubishi Oil CL	Mizushima	11,000	7,600	12,800	8,000	61,000	19,840	CAPABLE
Japan	Nippon Petroleum Refining CL	Negishi	0	3,960	0	17,550	68,075	12,735	CAPABLE
Japan	Tonen	Kawasaki	0	6,615	0	13,090	60,102	13,160	CAPABLE
Korea S.	Yukong Ltd.	Ulsan	27,000	5,400	27,900	6,210	111,150	27,675	CAPABLE
Singapore	Shell Eastern Petroleum Ltd.	Pulau Bukom	28,600	3,000	0	0	78,680	14,440	CAPABLE
Singapore	Singapore Refining Co. Pte. Ltd.	Pulau Merlimau	30,300	4,200	0	200	59,064	16,420	CAPABLE
Taiwan	Chinese Petroleum Corp.	Kaohsiung	18,080	3,200	60,000	2,500	91,728	29,682	CAPABLE
		Subtotal Capable	**219,980**	**84,575**	**106,100**	**147,350**	**911,893**	**278,072**	
Australia	Ampol Refineries Ltd.	Lytton	0	3,300	0	0	27,200	3,300	INCAPABLE
Australia	Australian Lubricating Oil Refinery Ltd.	Kurnell	0	0	0	0	0	0	INCAPABLE
Australia	BP Australia	Kwinana	0	2,430	0	11,700	28,548	8,280	INCAPABLE
Australia	BP Australia	Bulwer Island	0	1,890	0	10,800	16,025	7,290	INCAPABLE
Australia	Inland Oil Refiners	Eromanga	0	0	0	0	150	0	INCAPABLE
Australia	Mobil Oil Australia Ltd.	Altona	0	2,500	0	12,500	21,960	8,750	INCAPABLE
Australia	Mobil Oil Australia Ltd.	Adelaide (Port Stanvac)	0	0	0	0	6,840	0	INCAPABLE
Australia	Shell Refining (Australia) PL	Geelong	0	4,500	0	0	32,850	4,500	INCAPABLE
Australia	Shell Refining (Australia) PL	Clyde	0	3,000	0	0	27,270	3,000	INCAPABLE
Bangladesh	Eastern Refinery Ltd.	Chittagong	1,180	0	0	290	4,736	0	INCAPABLE
Brunei	Brunei Shell Petroleum CL	Seria	0	0	0	0	860	0	INCAPABLE
Burma	Myanmar Petrochemical Enterprise	Chauk	0	0	0	0	600	0	INCAPABLE
Burma	Myanmar Petrochemical Enterprise	Thanlyin (Mann)	0	0	0	0	3,536	0	INCAPABLE

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TABLE 7.7-1 (CONTINUED)
FAR EAST
(Barrels per Stream Day)

Country	Company	Location	Hydro-Cracking	Alkylation	Aromatics	Excess Naphtha HDS	GPI Factors	CARB SCORE	CARB CAPABILITY
China	Anqing Petrochemical	Anqing	0	1,000	0	4,000	19,825	3,000	INCAPABLE
China	Anshan Petrochemical	Anshan	0	0	0	0	15,501	0	INCAPABLE
China	Asphalt Plant of Liaohe Oil Field	Panjin	0	0	0	0	3,012	0	INCAPABLE
China	Baoding Petrochemical	Boading	0	0	0	0	803	0	INCAPABLE
China	Cangzhou Oil Refining	Cangzhou	0	0	0	0	6,010	0	INCAPABLE
China	Dagang Refinery	Dagang	0	0	0	0	2,008	0	INCAPABLE
China	Daqing Chemical Plant	Daqing	0	0	0	0	602	0	INCAPABLE
China	Daqing Petrochemical	Daqing	8,000	1,000	1,500	8,000	23,185	8,650	INCAPABLE
China	Duzishan Refining	Duzishan	8,000	0	0	2,000	16,040	0	INCAPABLE
China	Fujian Oil Refining	Fujian	0	0	0	0	13,221	0	INCAPABLE
China	Fushun Petrochemical	Fushun	8,000	3,000	0	0	66,872	6,200	INCAPABLE
China	Golmud Refinery	Qinhau	0	0	0	0	2,008	0	INCAPABLE
China	Guangzhou Petrochemical	Guangzhou	0	1,000	0	12,000	34,200	7,000	INCAPABLE
China	Hangzhou Refinery	Hangzhou	0	0	0	0	321	0	INCAPABLE
China	Harbin Refinery	Harbin	0	0	0	0	5,412	0	INCAPABLE
China	Huabei Chemical Pharmaceutical Plant	Shijiazhuang	0	0	0	0	402	0	INCAPABLE
China	Jianghan Petrochemical Plant	Qianjiang	0	0	0	0	241	0	INCAPABLE
China	Jiangnan Refinery	Jilin	0	0	0	0	602	0	INCAPABLE
China	Jilin Refinery	Qiangou	0	0	0	0	301	0	INCAPABLE
China	Jinan Oil Refining	Jinan	0	0	0	4,000	14,825	0	INCAPABLE
China	Jingmen Oil Refining	Jingmen	8,000	0	0	11,000	22,681	0	INCAPABLE
China	Jinling Petrochemical	Jinling	16,600	1,000	0	0	40,800	7,640	INCAPABLE
China	Jinxi Chemical	Jinxi	0	1,200	0	2,000	21,941	2,200	INCAPABLE
China	Jinzhou Petrochemical	Jinzhou	0	0	0	2,000	21,045	0	INCAPABLE
China	Jiujiang Oil Refining	Jiujiang	8,000	0	0	5,000	17,821	0	INCAPABLE
China	Karamay Refinery	Karamay	0	0	0	0	3,314	0	INCAPABLE
China	Lanzhou Chemical Industry Corp.	Lanzhou	0	0	0	0	1,700	0	INCAPABLE
China	Lanzhou Refining	Lanzhou	0	1,000	0	1,000	20,641	1,500	INCAPABLE
China	Liaoyang Chemical Fiber Corp.	Liaoyang	0	0	1,400	0	18,230	0	INCAPABLE
China	Linyuan Refinery	Linyuan	0	0	0	0	9,812	0	INCAPABLE
China	Luoyang Oil Refining	Luoyang	0	2,000	0	2,000	28,443	3,000	INCAPABLE
China	Majiatan Refinery	Lingwu	0	0	0	0	201	0	INCAPABLE
China	Maling Refinery	Qingyang	0	0	0	0	602	0	INCAPABLE
China	Mudanjiang Dongfanghong Refinery	Mudanjiang	0	0	0	0	402	0	INCAPABLE
China	Nanchong Refinery	Nanchong	0	0	0	0	301	0	INCAPABLE
China	Qianguo Oil Refining	Qianguo	0	0	0	0	12,612	0	INCAPABLE
China	Qingdao Petrochemical Plant	Qingdao	0	0	0	0	1,305	0	INCAPABLE
China	Refinery of Henan Oil Administration	Nanyang	0	0	0	0	241	0	INCAPABLE
China	Refinery of Jilin Petrochemical Co.	Jilin	0	0	0	0	8,635	0	INCAPABLE
China	Shanghai Gaoqiao Petrochemical	Shanghai Gaoqiao	0	1,000	0	0	32,600	1,000	INCAPABLE

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TABLE 7.7-1 (CONTINUED)
FAR EAST
(Barrels per Stream Day)

Country	Company	Location	Hydro-Cracking	Alkylation	Aromatics	Excess Naphtha HDS	GPI Factors	CARB SCORE	CARB CAPABILITY
China	Shengli Heavy Oil Plant	Dongying	0	0	0	0	2,008	0	INCAPABLE
China	Shengli Refinery	Dongying	0	0	0	0	301	0	INCAPABLE
China	Shijia Oil Refining	Shijiazhuang	0	1,000	0	0	19,400	1,000	INCAPABLE
China	Shongyuan Multi-Processing Plant	Puyang	0	0	0	0	301	0	INCAPABLE
China	Tianjin Petrochemical	Tianjin	0	1,000	2,000	0	27,050	1,600	INCAPABLE
China	Tianyang Refinery	Tianyang	0	0	0	0	100	0	INCAPABLE
China	Urumqi General Petrochemical	Wulumuqi	0	0	0	0	12,861	0	INCAPABLE
China	West Pacific Petrochemical	Dalian	0	2,250	0	0	26,870	2,250	INCAPABLE
China	Wuhan Oil Refining	Wuhan	0	1,000	0	0	14,021	1,000	INCAPABLE
China	Yanchang Oil & Mineral Administration	Yanchang	0	0	0	0	1,406	0	INCAPABLE
China	Yangzi Petrochemical	Yangzi	24,000	0	0	0	30,025	0	INCAPABLE
China	Yanshan Petrochemical	Yanshan	0	1,000	0	0	34,258	1,000	INCAPABLE
China	Yumen Refinery	Yumen	0	0	0	0	3,012	0	INCAPABLE
China	Zepu Petrochemical Plant	Zepu	0	0	0	0	301	0	INCAPABLE
China	Zhenhai Petrochemical	Zhenhai	0	1,000	0	0	27,778	1,000	INCAPABLE
India	Bharat Petroleum CL	Mahul Bombay	0	0	13,000	0	24,988	0	INCAPABLE
India	Bongaigaon Refinery & Petrochemicals Ltd.	Bongaigaon Assam	0	0	694	0	4,453	0	INCAPABLE
India	Cochin Refineries Ltd.	Cochin	0	0	12,000	0	27,902	0	INCAPABLE
India	Hindustan Petroleum CL	Mahul Bombay	0	0	0	0	15,845	0	INCAPABLE
India	Hindustan Petroleum CL	Mangalore	18,900	0	0	0	14,966	0	INCAPABLE
India	Hindustan Petroleum CL	Visakhapatnam	0	0	0	0	16,717	0	INCAPABLE
India	IBP CL	Numaligarh	0	0	0	0	12,350	0	INCAPABLE
India	Indian Oil CL	Barauni	0	0	0	0	10,180	0	INCAPABLE
India	Indian Oil CL	Digboi	0	0	0	0	1,323	0	INCAPABLE
India	Indian Oil CL	Gawahati	0	0	0	0	3,072	0	INCAPABLE
India	Indian Oil CL	Haldia	0	0	0	0	7,156	0	INCAPABLE
India	Indian Oil CL	Koyali	25,000	0	6,000	0	38,655	0	INCAPABLE
India	Indian Oil CL	Mathura	0	0	0	0	25,580	0	INCAPABLE
India	Madras Refineries Ltd.	Madras	0	0	0	0	17,566	0	INCAPABLE
Indonesia	Pertamina	Balikpapan	49,500	0	0	0	43,892	0	INCAPABLE
Indonesia	Pertamina	Balongan (EXOR-I)	0	0	0	0	58,700	0	INCAPABLE
Indonesia	Pertamina	Cepu	0	0	0	0	342	0	INCAPABLE
Indonesia	Pertamina	Cilacap	0	0	0	0	34,004	0	INCAPABLE
Indonesia	Pertamina	Dumai	50,220	0	0	0	37,352	0	INCAPABLE
Indonesia	Pertamina	Pangakalan Brandan	0	0	0	0	475	0	INCAPABLE
Indonesia	Pertamina	Sungaipakning	0	0	0	0	4,750	0	INCAPABLE
Indonesia	Pertamina	Wonokomo	0	0	0	0	300	0	INCAPABLE

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TABLE 7.7-1 (CONTINUED)
FAR EAST
(Barrels per Stream Day)

Country	Company	Location	Hydro-Cracking	Alkylation	Aromatics	Excess Naphtha HDS	GPI Factors	CARB SCORE	CARB CAPABILITY
Japan	Cosmo Oil CL	Sakai	0	7,200	0	2,700	25,570	8,550	INCAPABLE
Japan	Cosmo Oil CL	Chiba	0	0	0	8,550	35,400	0	INCAPABLE
Japan	Cosmo Oil CL	Yokkaichi City	0	0	0	0	23,725	0	INCAPABLE
Japan	Cosmo Oil CL (Asia Oil Co.)	Sakaide	0	0	0	0	20,140	0	INCAPABLE
Japan	Fuji Oil CL	Sodegaura	21,600	0	7,402	11,700	29,610	0	INCAPABLE
Japan	General Sekiyu Seisei KK	Sakai	0	0	19,800	5,400	28,440	0	INCAPABLE
Japan	Idemitsu Kosan CL	Himeji	0	0	0	9,900	13,300	0	INCAPABLE
Japan	Idemitsu Kosan CL	Ichihara, Chiba	10,440	0	12,060	7,200	43,046	0	INCAPABLE
Japan	Idemitsu Kosan CL	Tokuyama	0	0	0	0	20,400	0	INCAPABLE
Japan	Idemitsu Kosan CL	Tomakomai	13,500	0	0	8,100	27,110	0	INCAPABLE
Japan	Japan Energy	Chita	0	0	15,300	5,800	14,720	0	INCAPABLE
Japan	Japan Energy	Funakawa	0	0	0	0	600	0	INCAPABLE
Japan	Kainan Petroleum Refining CL	Kaiwan City	0	0	0	0	5,000	0	INCAPABLE
Japan	Kashima Oil CL	Kashima	0	0	2,900	900	26,820	0	INCAPABLE
Japan	Koa Oil CL	Osaka	0	4,000	2,100	1,000	24,400	5,130	INCAPABLE
Japan	Koa Oil CL	Marifu	0	0	7,500	8,000	24,920	0	INCAPABLE
Japan	Kyenus Sekiyu Seisei KK	Kawasaki	0	0	0	0	6,650	0	INCAPABLE
Japan	Kyokuto Petroleum Ltd.	Chiba	35,000	0	0	2,500	39,500	0	INCAPABLE
Japan	Kyushu Oil CL	Oita	11,000	0	0	1,000	24,000	0	INCAPABLE
Japan	Mitsubishi Oil CL	Kawasaki	0	0	0	0	7,500	0	INCAPABLE
Japan	Nansei Sekiyu KK	Nishihara	0	0	0	10,400	10,000	0	INCAPABLE
Japan	Nihonkai Oil CL	Toyama	0	0	0	4,000	6,000	0	INCAPABLE
Japan	Nippon Oil CL	Niigata	0	0	0	0	4,270	0	INCAPABLE
Japan	Nippon Petroleum Refining CL	Muroran	36,000	0	0	14,400	38,830	0	INCAPABLE
Japan	Nippon Petroleum Refining CL	Nakagusuku	0	0	0	0	0	0	INCAPABLE
Japan	Nippon Petroleum Refining CL	Yokohama (Dismantled)	0	0	0	180	0	0	INCAPABLE
Japan	Nippon Refining	Kudamatsu	0	0	0	0	0	0	INCAPABLE
Japan	Okinawa Sekiyu Seisei	Yonashiro	0	0	0	5,000	11,000	0	INCAPABLE
Japan	Seibu Oil CL	Yamaguchi	0	0	0	8,100	22,020	0	INCAPABLE
Japan	Showa Shell Sekiyu KK	Kawasaki	0	0	3,300	5,800	11,010	0	INCAPABLE
Japan	Showa Shell Sekiyu KK	Niigata	0	0	0	0	3,670	0	INCAPABLE
Japan	Showa Yokkaichi Sekiyu CL	Yokkaichi	0	0	5,500	20,900	31,070	0	INCAPABLE
Japan	Taiyo Oil CL	Ehime	16,200	0	11,800	6,300	14,935	0	INCAPABLE
Japan	Teiseki Topping Plant	Kubiki	0	0	0	0	419	0	INCAPABLE
Japan	Toa Oil CL	Kawasaki	0	0	0	11,340	25,363	0	INCAPABLE
Japan	Toho Oil CL	Owase	0	0	0	0	3,500	0	INCAPABLE
Japan	Tohoku Oil CL	Sendai	0	0	0	0	18,390	0	INCAPABLE
Japan	Tonen	Wakayama	0	2,079	0	0	31,374	2,079	INCAPABLE
Korea N.	Government	Paengma-ri	0	0	0	0	2,900	0	INCAPABLE
Korea N.	Government	Sonbong	0	0	1,000	100	4,200	0	INCAPABLE

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TABLE 7.7-1 (CONTINUED)
FAR EAST
(Barrels per Stream Day)

Country	Company	Location	Hydro-Cracking	Alkylation	Aromatics	Excess Naphtha HDS	GPI Factors	CARB SCORE	CARB CAPABILITY
Korea S.	Hanhwa	Inchon	0	0	18,000	0	26,125	0	INCAPABLE
Korea S.	Hundai	Busan	0	0	0	1,800	0	0	INCAPABLE
Korea S.	Hyundai Oil Ref Co.	Daesan	22,000	0	0	7,000	41,670	0	INCAPABLE
Korea S.	LG-Caltex	Yosu	0	0	20,700	7,200	82,200	0	INCAPABLE
Korea S.	Ssangyong Oil Refining CL	Onsan	27,000	0	9,600	0	52,695	0	INCAPABLE
Malaysia	Esso Malaysia Berhad	Port Dickson	0	0	0	9,700	8,000	0	INCAPABLE
Malaysia	Petronas	Melaka	0	0	0	0	10,000	0	INCAPABLE
Malaysia	Petronas Penapisan Sdn. Berhad	Kerteh	0	0	0	0	7,500	0	INCAPABLE
Malaysia	Sarawak Shell Berhad	Luton	0	0	0	0	4,500	0	INCAPABLE
Malaysia	Shell Refining Co. Berhad	Port Dickson	0	0	0	15,000	10,500	0	INCAPABLE
New Zealand	New Zealand Refining	Whangarei	24,300	0	0	9,900	18,840	0	INCAPABLE
Pakistan	Attock Refinery Ltd.	Rawalpindi	0	0	0	0	2,898	0	INCAPABLE
Pakistan	National Refinery Ltd.	Karachi	0	0	0	0	6,205	0	INCAPABLE
Pakistan	Pakistan Refinery Ltd.	Karachi	0	0	0	0	4,630	0	INCAPABLE
Philippines	Caltex (Philippines) Inc.	Batangas	0	0	0	0	12,200	0	INCAPABLE
Philippines	Petron Corp.	Limay	0	0	0	17,100	20,125	0	INCAPABLE
Philippines	Philippine Petroleum Corp.	Pililla	0	0	0	0	0	0	INCAPABLE
Philippines	Pilipinas Shell Petroleum	Tabangao	0	0	0	12,200	21,490	0	INCAPABLE
Singapore	BP Refinery Singapore PL	Pasir Panjang	0	0	0	0	0	0	INCAPABLE
Singapore	Esso Singapore PL	Pulau Ayer Chawan	4,400	0	0	11,400	29,410	0	INCAPABLE
Singapore	Mobil Oil Singapore PL	Jurong	26,000	0	15,000	24,000	42,060	0	INCAPABLE
Sri Lanka	Ceylon Petroleum Corp.	Sapugaskanda	0	0	0	0	5,988	0	INCAPABLE
Taiwan	Chinese Petroleum Corp.	Taoyuan	0	0	0	6,200	20,000	0	INCAPABLE
Thailand	Bangchak Petroleum	Bangkok	0	0	0	1,350	12,000	0	INCAPABLE
Thailand	Esso Standard Thailand Ltd.	Sriracha	0	0	0	11,500	27,400	0	INCAPABLE
Thailand	Fang Refining	Fang	0	0	0	0	170	0	INCAPABLE
Thailand	Rayong Refining	Rayong	40,000	0	0	0	32,700	0	INCAPABLE
Thailand	Star Petroleum	Map Ta Phut	0	0	0	0	25,670	0	INCAPABLE
Thailand	Thai Oil CL	Sriracha	19,900	0	0	0	35,054	0	INCAPABLE
Thailand	Thai Petrochemical Co.	Rayong	0	0	0	0	6,500	0	INCAPABLE
		Subtotal Capable	**532,740**	**50,349**	**188,556**	**381,910**	**2,505,884**	**98,919**	
		TOTAL	**752,720**	**134,924**	**294,656**	**529,260**	**3,417,777**	**376,991**	

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8. KEY COMPONENT AVAILABILITY

The volume of CARBOB that can be produced from a region will be assessed in two steps. First, an estimate will be made of the volume of alkylate that can be made available. This volume will depend on total alkylate production capability and an estimate of the fraction of total alkylate that might be released for CARBOB production. Alkylate from CARBOB-Incapable refineries is assumed not to be available and only a fraction of alkylate from CARBOB-Capable refineries might be released. The second step involves an estimate of the volume of CARBOB that can be produced from each volume of alkylate. The principal factors influencing this ratio are the volumes and qualities of other blend stocks that can be combined with the alkylate.

8.1 ALKYLATE

Table 8.1-1 shows the alkylate capacity of CARBOB-Capable refineries in each region. In addition this table shows our estimate of the total production of alkylate from CARBOB-Capable refineries in each region. Like any refinery process unit, alkylation units do not regularly produce at 100% of capacity. A lower utilization is common resulting from unit maintenance downtime as well as feed availability and economic issues. Alkylation units normally are constructed as adjuncts to FCC units which are economically important to refinery operations. Often FCC units operate at higher utilization rates than refineries as a whole. Consistent with information from diverse data sources and based on other work prepared by Purvin & Gertz, utilization rates have been assigned for alkylation units in each region ranging from 75% to 85%.

TABLE 8.1-1
ALKYLATE AVAILABILITY
(Barrels per Day)

	Alkylate Capacity	Estimated Production	Alkylate Availability
Pacific North West	12,000	10,000	4,000
U.S. Gulf Coast	503,000	428,000	86,000
Caribbean	22,000	18,000	11,000
Europe	158,000	134,000	27,000
Latin America	84,000	63,000	25,000
Middle East	27,000	21,000	8,000
Far East	85,000	68,000	14,000
TOTAL	**891,000**	**742,000**	**175,000**

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Furthermore, alkylate availability for CARBOB was estimated. These estimates were prepared based on discussions with refiners and in light of our own views of technical factors limiting alkylate availability in the USGC region which is responsible for over half of all alkylate production in the world. Alkylate availability for CARBOB doesn't necessarily translate into alkylate availability for sale as a gasoline blend stock.

8.2 OTHER COMPONENTS

Table 8.2-1 shows the estimated availabilities of other gasoline blend stocks. These volumes were determined based on the production capacity of each type of process unit from CARBOB-Capable refineries. Those capacities were multiplied by the GPI factors for each process unit, a typical yield of gasoline-range material from the units, and a standard 85% utilization factor.

TABLE 8.2-1
MAJOR BLEND STOCK PRODUCTION
CARBOB CAPABLE REFINERIES
(Barrels per Day)

	Hydrocrackate	Desulfurized, LSR	Aromatics Raffinate	FCC Gasoline	Reformate	Total
Pacific North West	0	6,000	0	21,000	18,000	45,000
U.S. Gulf Coast	213,000	171,000	55,000	1,105,000	1,112,000	2,656,000
Caribbean	0	28,000	8,000	81,000	105,000	222,000
Europe	81,000	400,000	3,000	344,000	397,000	1,225,000
Latin America	0	25,000	3,000	193,000	70,000	291,000
Middle East	30,000	24,000	0	62,000	45,000	161,000
Far East	75,000	125,000	27,000	242,000	335,000	804,000
TOTAL	**399,000**	**779,000**	**96,000**	**2,048,000**	**2,082,000**	**5,404,000**

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No estimate was made of the fraction of each of the other blend stocks that could be made available for CARBOB blending. First, the total volumes of other blend stocks tend to be much greater than alkylate. Hence alkylate is the blend stock typically in shortest supply. Second, while alkylate is a key ingredient in a few high value products such as premium gasoline, reformulated gasoline or aviation gasoline, none of the other components is particularly important to any end product other than conventional regular grade motor gasoline. The opportunity cost of conventional regular grade motor gasoline will be the starting point for calculating the cost of producing CARBOB. While diverting too much alkylate toward CARBOB might impact production of higher valued products raising the opportunity costs, this is not likely for the other blend stocks. Consequently any constraints imposed on blending with these other components by limiting their availability to CARBOB were viewed as unnecessary.

8.3 CARBOB/ALKYLATE RATIO CLASSES

The predictive model was used in conjunction with estimated blend stock qualities for each region of the world to estimate how much CARBOB could be produced from each barrel of alkylate. Air toxics as well as criteria pollutants must be controlled and were considered in estimating blend opportunities. These ratios are viewed as reasonable representations of how blending could occur in a real world situation and we are confident that the ratios do not over-estimate the technical capability to blend CARBOB.

The CARBOB/Alkylate ratios do not reflect the result of optimized refinery models. Inasmuch as for most regions there are many refineries operating that can provide CARBOB components, it is believed that optimizing the CARBOB blending would tend to over-estimate CARBOB producibility in a way for which there would be no ready calibration or correction. Consequently we believe that optimized CARBOB blending using the blend stock qualities we adopted would result in higher ratios than we are using in this work.

Typical blend stock qualities vary depending on the level of sophistication in a region and the types of crude oils processed. Blend stock qualities were estimated based on Purvin & Gertz experience in other refining assignments and were not generated from refinery models or statistical sources for this assignment.

CARBOB/Alkylate ratios vary widely. Refineries that have only moderately high sulfur FCC gasoline streams with which to blend, conventional, high benzene reformates, and no hydrocrackates or raffinates, typically find CARBOB/Alkylate ratios in the 2.0-2.5 range. At the other end of the spectrum, California refiners who have invested heavily to meet CARB requirements are able to operate with CARBOB/Alkylate ratios in the 6-7 range.

Refiners in distant markets supplying only a small fraction of their gasoline as CARBOB face fewer problems than California refiners who have to produce most or all their gasoline to CARB specifications. Such refiners are able to pick and choose the best blend stocks and divert less attractive materials to other markets for which they are still well suited. Nevertheless, these refiners are unlikely to exceed the CARBOB/Alkylate ratios achieved by California refiners because of the very heavy investments California refiners have made to overcome the obstacles posed by CARB specifications.

In principle CARBOB could be manufactured relying entirely on hydroprocessing including hydrocracking, reforming and hydrotreating. Such an approach would not utilize FCC or alkylation technology and therefore would not use alkylate. The ARCO Cherry Point refinery operates in that manner and is expected to be able to make useful blend stocks at a minimum. Such refineries have the advantage of very low sulfur and zero olefins in all their blend stocks. On the other hand, unless special steps are taken to minimize aromatics and benzene, levels of these materials tend to be very high with this configuration. Outside the U.S. and parts of Western Europe, world benzene controls do not approach the stringency required for CARB gasoline if they exist at all. That factor combined with the dearth of many examples of this type of process orientation indicates that special consideration of these refineries is unwarranted.

The CARBOB/alkylate ratio is sensitive to the selection of oxygenate and varies across cases. Using minimum ethanol without an RVP waiver leads to the lowest ratios since dilution effects are small and a particularly low vapor pressure must be observed on the CARBOB, about 5.8 PSIA. Other oxygenates lead to higher CARBOB/Alkylate ratios.

There is considerable uncertainty in determining the CARBOB/Alkylate ratio to a high degree of accuracy. The ratio is highly dependent on details of stream compositions that are not known for individual refineries and on the level of sophistication with the predictive model that the refiner can achieve. To respond to this difficulty and to avoid over-

optimizing the problem, refiners and cases were assigned to CARBOB/Alkylate ratio classes. Classes used are shown in Table 8.3-1.

TABLE 8.3-1
CARBOB/ALKYLATE RATIOS

Low	2.5
Moderate	3.5
High	5.5

Each region in each case was assigned to one of these three ratio classes. Using these class values and the estimate of the volume of alkylate available from each region, the available volume of CARBOB was determined.

8.4 CARBOB/ALKYLATE RATIOS

Each region and case was assigned to one of the CARBOB/Alkylate ratio classes. These assignments were made in consideration of the blend stocks available and the requirements of the case. Table 8.4-1 shows the assignments that were made.

TABLE 8.4-1
CARBOB/ALKYLATE RATIO CLASS ASSIGNMENTS

	Ethanol No Waiver	Ethanol Waiver	TBA	ETBE	Mixed Oxygenates	No Oxygenate
Pacific North West	Low	Low	Medium	Medium	Medium	Low
U.S. Gulf Coast	Low	Low	High	High	High	Low
Caribbean	Low	Low	Low	Low	Low	Low
Europe	Low	Low	High	High	High	Low
Latin America	Low	Low	Low	Low	Low	Low
Middle East	Low	Low	Low	Low	Low	Low
Far East	Low	Low	Low	Low	Low	Low

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Four regions, the Caribbean, Latin America, Middle East and Far East, stood out as having relatively poor control of blend stock qualities. The Hess refinery in the Caribbean is the sole producer and even though much of the refinery's production is oriented toward the U.S. East Coast market, overall sophistication did not seem to support assignment to either the medium or high classes. Latin American and Middle Eastern refineries generally produce only into markets with loose product specifications. The Far East includes Japanese refineries that produce to stringent specifications but those refineries were not the ones considered most likely to produce CARBOB, mostly for logistical reasons. The Chinese market does not have stringent controls and still consumes leaded gasoline. Chinese refiners are the largest group of Far Eastern refiners thought to have reasonable prospects of manufacturing some CARBOB.

The Gulf Coast and Europe are thought to have the best prospects for having high CARBOB/Alkylate ratios. Both regions have very large refining systems and the refineries have a high level of technical sophistication. The European refiners will be entering an era of much lower benzene specifications and the Gulf Coast refiners already are there. Both regions are being called on to produce some gasoline to stringent environmental specifications which are becoming more stringent.

The introduction of more stringent gasoline specifications in Europe and the U.S. could have an unfavorable or favorable impact on CARBOB availability. Refiners in those markets will have to meet new, more stringent specifications which, apart from any capital improvements, diminishes the availability of high quality blendstocks for CARBOB. On the other hand, these refiners as a group generally will respond with expansions or other improvements that increase the pool of high quality materials. The net of these changes is reflected in the information in this section. There is irreducible uncertainty associated with future availability as the actions of the refiners cannot be completely foreseen.

The Pacific North West is a special case. It was assigned to the medium class in part because of its proximity to California and the perceived opportunities for multi-refinery optimization with California. The terms under which Shell is selling the refinery are not known and may negatively influence availability in the future.

The most challenging cases are both ethanol cases and the no oxygenate case. The ethanol case with no RVP waiver requires substantially more stringent RVP blending than all other cases. While it was assumed that adequate debutanization exists, the added difficulty of this case would be expected to be reflected in some reduced ability to manufacture CARBOB. The ethanol waiver case runs into difficulty due to the high oxygen content. The no oxygenates case is more difficult principally because the octane requirements of the case are appreciably higher. In all the oxygenate cases, CARBOB could be blended well below 87 octane due to the octane available from the oxygenates to be added in California. The no oxygenate case required 87 octane of the CARBOB limiting ability to utilize low octane stocks. Furthermore, there is no dilution effect available from the oxygenates in this case. Our review indicated that these factors would not be enough to warrant lower class assignments but as will be discussed in Section 9, they do result in higher costs.

8.5 CARBOB SUPPLIES

CARBOB supplies available from each region in each case were determined by multiplying the alkylate available for CARBOB by the class ratio for that case and region. Table 8.5-1 shows the CARBOB availability for each region for the California only MTBE ban.

TABLE 8.5-1
CARBOB AVAILABILITY
CALIFORNIA ONLY MTBE BAN
(Barrels per Day)

	Ethanol No Waiver	Ethanol Waiver	TBA	ETBE	Mixed Oxygenates	No Oxygenates
Pacific North West	10,000	10,000	14,000	14,000	14,000	10,000
U.S. Gulf Coast	214,000	214,000	470,000	470,000	470,000	214,000
Caribbean	26,000	26,000	26,000	26,000	26,000	26,000
Europe	67,000	67,000	148,000	148,000	148,000	67,000
Latin America	63,000	63,000	63,000	63,000	63,000	63,000
Middle East	21,000	21,000	21,000	21,000	21,000	21,000
Far East	34,000	34,000	34,000	34,000	34,000	34,000

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Table 8.5-2 shows the CARBOB availability for each region for the U.S. wide MTBE ban. The differences among these tables are limited to the USGC region.

TABLE 8.5-2
CARBOB AVAILABILITY
US WIDE MTBE BAN
(Barrels per Day)

	Ethanol No Waiver	Ethanol Waiver	TBA	ETBE	Mixed Oxygenates	No Oxygenates
Pacific North West	10,000	10,000	14,000	14,000	14,000	10,000
U.S. Gulf Coast	107,000	107,000	235,000	235,000	235,000	107,000
Caribbean	26,000	26,000	26,000	26,000	26,000	26,000
Europe	67,000	67,000	148,000	148,000	148,000	67,000
Latin America	63,000	63,000	63,000	63,000	63,000	63,000
Middle East	21,000	21,000	21,000	21,000	21,000	21,000
Far East	34,000	34,000	34,000	34,000	34,000	34,000

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9. SUPPLY COST ESTIMATES

Supply costs were estimated based on the cost of gasoline in each region to which were added cost components representing refinery processing costs, cargo consolidation costs, transportation costs and refiner margin. An octane adjustment was needed to account for the benefit or debit available to the refiner of being able to supply gasoline at an octane different than that prevailing the local market. The processing cost and octane adjustment would be affected by the selection of oxygenate. None of the other cost elements is sensitive to the substitute oxygenate selected.

9.1 BASE GASOLINE COST BY REGION

Base gasoline costs for each region were estimated based on market data for the May through August summer season of 1997. Gasoline costs were determined based on spot price quotations for various markets. Spot price quotations are the best measure of arm's length gasoline values in large volume shipments priced at the refinery gate. Spot price quotations are commonly used in refinery economic analysis work. Other measures of gasoline cost such as rack prices or retail prices are considered inferior measures and would require correction to be used to estimate the cost of supplying imported CARBOB to California. Generally prices other than spot prices would result in over-estimation of the cost of supplying CARBOB. Base gasoline costs were directly available from market. Table 9.1-1 shows the base gasoline costs used for each market. For reference, the average summertime 1997 spot price of CARB reformulated gasoline is estimated to have been 63.7 cents per gallon.

TABLE 9.1-1
BASE GASOLINE COSTS BY REGION
(Cents per Gallon)

Pacific North West	60.9
U.S. Gulf Coast	59.6
Caribbean	59.5
Europe	55.3
Latin America	59.1
Middle East	58.9
Far East	60.5

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9.2 PROCESSING COSTS

Processing costs are small when the CARBOB volume is limited. The least expensive increment of CARBOB supply would be that supply that could be provided with minimal interference with normal refinery operations. That increment would be provided mostly by providing special blends of existing refinery gasoline blend stocks rather than by reconfiguring refinery processing operations or selecting superior feed stocks. Some extra debutanization might occur to ensure that CARBOB RVP specifications could be met. As

the fraction of a refinery's gasoline production dedicated to CARBOB rises, then more intensive and expensive changes in the operations or hardware configuration of the refinery are needed. A substantial part of the supply curve for CARBOB can be identified without resorting to high cost methods and that part of the supply curve is expected to be adequate to cover any shortfalls that may result from an MTBE ban.

When refineries are producing limited volumes of CARBOB, most processing costs incurred are blending costs. These costs are reflective mostly of the lost opportunity to blend low cost butane with gasoline. The butane blending opportunity is lost due to the lower vapor pressure required to meet CARB specifications. Butane typically carries a cost well below that of gasoline. Typical summertime gasoline RVP specifications allow some butane to be blended with gasoline but CARB specifications call for such a low RVP that essentially no butane can be blended into CARB gasoline or CARBOB. A refiner electing to manufacture to CARBOB specifications rather than to other, higher vapor pressure specifications would lose the opportunity to profit by blending low cost butane as part of higher valued gasoline.

Processing costs were estimated based on the amount of lost opportunity to blend butane and the prevailing costs of butane and gasoline in each market. Costs vary from region to region because some regions have higher gasoline RVP specifications and because butane and gasoline prices are not the same in all world locations.

A provision of 0.5 cents per gallon of CARBOB was made for incidental direct costs such as costs to clear tankage, extra laboratory testing, any extra energy costs that might be related to more severe debutanization and the like. Table 9.2-1 shows the processing costs for each case.

TABLE 9.2-1
PROCESSING COSTS BY REGION
(Cents per Gallon)

	Ethanol	ETBE	TBA	Others
Pacific North West	4.2	2.8	3.3	3.2
U.S. Gulf Coast	2.0	1.0	1.3	1.3
Caribbean	1.9	1.0	1.2	1.1
Europe	2.8	1.8	2.1	2.0
Latin America	1.7	1.0	1.1	1.1
Middle East	2.0	1.0	1.3	1.2
Far East	2.6	1.8	2.0	2.0

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9.3 OCTANE CREDIT/DEBIT

Octane of regular gasoline, suitable for most automobiles, is typically about 87 (R + M)/2 or about 91 RON. Few markets can be found in which many automobiles will accept substantially lower octane. Many countries also have a lower octane grade commonly used

in low compression engines, motorcycles and the like. Price quotations are available for the automotive grades in many locations and these formed the basis for our analysis.

CARBOB could be produced to substantially lower octane than prevailing automotive gasoline specifications. Substantial octane is provided by the oxygenates that are added to CARBOB to produced finished CARB gasoline. Table 9.3-1 below shows the octane of CARBOB needed for each case:

TABLE 9.3-1
CARBOB OCTANE
(R+M)/2

Oxygenate	Oxygenate Octane	Oxygenate Blend Fraction	CARBOB Octane
MTBE	110	0.110	84.2
ETOH - No Waiver	115	0.058	85.3
ETOH - Waiver	115	0.100	83.9
TAME	105	0.124	84.5
ETBE	112	0.127	83.4
TBA	100	0.088	85.7
Mixed	106	0.110	84.5
None	--	--	87.0

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Table 9.3-1 shows the octane for each oxygenate. The mixed oxygenate octane used was the average of the octanes of TAME, ETBE and TBA. The oxygenate blend fraction is the fraction of a final CARB gasoline blend that would be each oxygenate to achieve 2.0 per cent oxygen in the gasoline. For example a CARBOB using ethanol would be 5.8% ethanol to achieve 2.0 percent oxygen. However, federal law requires that the ethanol waiver case contain 10% ethanol in the blend. The last column of Table 9.3-1 shows the octane of the CARBOB that would be blended with the oxygenate to achieve a CARB gasoline octane of 87.

Octane is costly to refiners. Converting low octane materials into high octane materials involves expensive processing like catalytic reforming or costly high octane additives like MTBE. Conversely producing a lower octane product represents a real cost savings to the refiner. Octane costs are not linear in all ranges and the cost for octane at very high ranges is higher than the cost at lower octane ranges. For purposes of evaluating octane costs, we have used a figure of 21 cents per octane barrel or 0.5 cents per octane gallon. These numbers are considered to be at the lower end of the octane cost spectrum.

Even if refiners do not alter processing, they can benefit from producing a lower octane product. Higher octane stocks can be diverted to producing more higher valued premium gasoline and less lower valued regular gasoline.

Because CARBOB can be produced at substantially lower octane than prevailing automotive specifications require and because that octane savings can translate either into

refinery cost reductions or to more higher valued premium products (apart from CARBOB), it is appropriate to assign an octane credit to the CARBOB. This credit has been calculated as the octane difference between 87 and the octane of the CARBOB multiplied by 0.5 cents per octane gallon. This credit has the effect of reducing the cost of delivering CARBOB to California. If octane becomes more valuable because of an MTBE ban, then a larger credit would be available. In the interest of conservatism, the lower octane value and credit was used.

China was treated as a special case. China uses lower octane gasoline than most other countries and China is a likely Far Eastern supplier of CARBOB. China is the country that historically has been the largest single supplier of foreign gasoline to California prior to the introduction of CARB gasoline. For these reasons, China's cost structure was chosen to represent Asian suppliers. Because China's gasoline octane is low, about 85 (R+M)/2 on an unleaded basis, the octane credit available to Chinese refiners is correspondingly low.

Table 9.3-2 shows the octane credits for each oxygenate case.

TABLE 9.3-2
OCTANE COST
(Cents per Gallon)

	Far East	Other [1]
Ethanol - Waiver	-0.5	-1.6
Ethanol - No Waiver	0.1	-0.9
ETBE	-0.8	-1.8
TBA	0.4	-0.6
Mixed Oxygenate	-0.2	-1.2
No Oxygenate	0.0	0.0

Note: Based on 87 (R+M)/2 gasoline for all regions except Far East.
Far East is based on 85 (R+M)/2.

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9.4 INVENTORY HOLDING COSTS

Refiners in distant location who produced CARBOB will experience an increase in the amount of time which elapses between their completion of the manufacturing and the time the product is received at the consumption point. Similarly, California consumers using CARB gasoline produced in distant locations rather than in California will experience an increase in the amount of time that elapses between the time the gasoline is produced by the refinery and the time that it is available for purchase. Holding inventory for this additional period of time adds to the cost of supplying fuels. The additional inventory holding costs were calculated based on an estimated additional time and an interest rate. Table 9.4-1 shows the additional costs of holding inventory for each region. The number of additional days inventory is held is dependent on shipping time to California. Costs were estimated based on an interest rate of 8% per annum. There has been no assumption

about the specific contract terms and whether these costs are part of the invoiced price for fuel delivered by the distant supplier. No capital investment has been included in this analysis to provide for additional tankage for this purpose.

TABLE 9.4-1
INVENTORY HOLDING COSTS BY REGION
(Cents per Gallon)

Pacific North West	0.3
U.S. Gulf Coast	0.4
Caribbean	0.4
Europe	0.6
Latin America	0.4
Middle East	0.4
Far East	1.8

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There has been neither a specific assessment of nor provision for the additional risk associated with holding the inventory. The degree to which existing California gasoline suppliers feel the need or the ability to hedge their inventory exposure is not clear. While any individual transaction may be subject to risk of a price fall during delivery, over time price increases and decreases tend to cancel out and the cost associated with the additional risk of holding the inventory, as distinct from the cost of capital, is thought to be small relative to the overall costs of an MTBE ban.

9.5 TRANSPORTATION COSTS

Transportation costs have been defined to include the cost of marine transportation as well as the cost of third party terminaling at the point of destination.

“Worldscale” refers to the New Worldwide Tanker Nominal Freight Scale as published annually by the Worldscale Associations of London and New York. The Worldscale schedule provides standardized shipping costs between world petroleum ports and includes consideration of shipping time, typical carriage terms, relevant port and canal fees and the like. Worldscale is widely used to estimate consistent shipping costs for diverse voyages.

Typically, large tankers with relatively low per unit costs charge a fraction of the standard Worldscale rates while small tankers with high costs charge a multiple of standard Worldscale rates. Similarly “clean” vessels suitable for gasoline or diesel fuel charge a higher rate than “dirty” vessels which have contained crude oil or fuel oil. Quotations for the typical tanker charges, relative to Worldscale, are found in many shipping and petroleum industry publications.

Gasoline typically would not be carried internationally in tankers larger than the LR-1 class. LR-1 class tankers are 45,000-80,000 deadweight tonnes which translates into cargo capacity around 15 to 27 million gallons. Though gasoline might also be carried in

smaller MR class tankers, we selected LR-1 class tankers for this analysis since the tanker size is a reasonable maximum resulting in the lowest reasonable shipping cost.

Marine transportation costs have been estimated on an arm's length basis. While many oil companies use their own ships, their incurred costs are considered irrelevant to the issue at hand and many prospective suppliers do not have ships available to transport CARBOB to California. Shippings costs were estimated based on Worldscale rates with a market factor of 1.5 applied to account for clean LR-1 sized vessels. This market factor is consistent with market conditions in summer 1997 and is not unusual for clean LR-1 vessels. Worldscale rates, quoted in US dollars per tonne were converted to dollars per gallon based on 353 gallons per tonne.

Worldscale quotations are not useful for voyages from the Pacific North West or USGC to California because of the federal requirement to use Jones Act tankers on such routes. Jones Act tankers must be American flagged and also have been built in U.S. shipyards. Jones Act tankers typically carry much higher costs than international flag carriers. Costs to use Jones Act tankers were estimated based directly on opinions of industry participants. For purposes of this assessment, it has been assumed that adequate Jones Act tonnage could be accessed without adding to costs and costs above the minimum level quoted for Jones Act movements have been used to account for market changes attributable to the increase in movements that might occur in the event of an MTBE ban.

There is some risk that delivering large volumes of CARBOB, alkylate or other products to California and that shipping large volumes of non-CARB gasoline or intermediates away from California might disrupt typically observed ship availabilities or costs. Since such trade would be a very small fraction of international clean products movements, such risk for international origins or destinations is considered small. Domestic shipments would need to be moved using Jones Act carriers, the supply of which is much smaller. Since domestic sources of alkylate or CARBOB might be quite important, a shortage of Jones Act carriers has the potential to shift supply curves.

In the long term, it would be possible, if appropriate contracts for use were in place, to build new Jones Act carriers. New carriers are quite unlikely to be built unless the need for them were expected to be sustained long enough to amortize tanker costs. New tankers meeting new design criteria might logically carry higher costs than older tankers but if such tankers could be designed and dedicated full time to carrying CARBOB or alkylate on domestic routes, the costs could be optimized. Furthermore, the possibility of backhaul cargoes which might develop would further improve cargo-carrying utilization and reduce costs further.

There is a reasonable possibility that if there were long term demand for transportation from the U.S. Gulf Coast to California that pipeline transportation systems might supplant marine shipments for some or most of the business. A project which is under construction but not yet completed is expected to link the Gulf Coast refineries directly to El Paso and allow gasoline from the U.S. Gulf Coast to be shipped as far as Phoenix. If there were adequate shipper interest in doing so, it is possible that the existing pipeline system

connecting Los Angeles to Phoenix and El Paso to Phoenix could be expanded and/or reconfigured to allow some volumes of U.S. Gulf Coast products to penetrate California markets. Other pipeline systems in other services that are or could become underutilized might also be used. While evaluation of how speculative pipeline reconfigurations or new construction might contribute to transporting CARBOB or alkylate to California is beyond the scope of this report, in the long term the possibility that entrepreneurs would make use of such systems to serve any reliable, long term need that develops cannot be dismissed.

In the intermediate term, there would not be adequate time to build new tankers or reconfigure pipelines and a Jones Act carrier shortfall could influence CARBOB or alkylate supply patterns. In the event of a shortage of carriers, less efficient and more costly foreign sources might be preferred to potentially less costly domestic products. In principle if Jones Act carriers were simply unavailable product shipments from the U.S. Gulf Coast simply could not be increased regardless of cost or price considerations.

The availability of Jones Act carriers and its potential impact on supplies from the U.S. Gulf Coast or Pacific North West is more fully discussed in the Marine Infrastructure report.

There are miscellaneous charges that must be paid to port and government bodies apart from those covered by Worldscale. These include federal and state oil spill taxes or fees, wharfage, customs duties, other customs charges, and the like. Customs duties are required only on imports from foreign points of origin and not for shipments from either the Pacific North West or the USGC. These have been included for Caribbean points of origin even though the most likely origin of such shipments is the U.S. Virgin Islands since duties might not have been paid on the foreign crude oil used to manufacture products in St. Croix.

On arrival in California, waterborne CARBOB cargoes would require terminaling and blending with the oxygenate. If ethanol is the oxygenate chosen, then the blending would occur as the trucks is loaded to transport the CARB gasoline to the service stations. Otherwise, the blending would occur at or near the marine offloading port.

Marine cargoes of CARBOB most likely would not be handled by refineries but rather would be diverted to marine terminals. While refineries can handle small volumes of inbound blend stocks or even finished products, their tankage and logistics systems are oriented toward inbound crude oil movements and outbound product movements. Furthermore, there is no reason CARBOB would have to be handled at refineries since marine terminals could perform all necessary blending.

A provision of 0.75 cents per gallon was added to provide for average costs for handling and blending at marine terminals in California. This cost level is considered a reasonable average for high volume throughput through existing terminals. Terminaling costs are addressed more completely in the Adequacy of Marine Infrastructure study.

Table 9.5-1 shows the buildup of transportation costs.

TABLE 9.5-1
TRANSPORTATION COSTS BY REGION
(Cents per Gallon, Except as Noted)

Origin	WS100, ($/MT)	Transport	Misc.	Terminalling	Total
Pacific North West	----	5.1	0.5	0.8	6.4
U.S. Gulf Coast	----	8.0	0.5	0.8	9.3
Caribbean	7.7	3.9	1.8	0.8	6.4
Europe	13.6	6.4	1.8	0.8	8.9
Latin America	7.7	3.9	1.8	0.8	6.4
Middle East	19.0	8.1	1.8	0.8	10.6
Far East	10.0	4.2	1.8	0.8	6.8

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9.6 REFINER MARGINS

Refiners outside California will not undertake the expense and nuisance of producing CARBOB unless there is the promise of reasonable profit from doing so. Covering direct costs is an inadequate incentive since there are risks to the refiner and he may incur indirect and opportunity costs which have not been assessed elsewhere in this cost buildup. A provision of 2 cents per gallon has been assigned to all cases to provide for indirect and opportunity costs, other small costs not assessed elsewhere and for refiner margin or profit from producing CARBOB in distant locations.

9.7 TOTAL CARBOB COST

Tables have been prepared showing the total costs of providing CARBOB from outside California. Tables 9.7-1 through 9.7-6 show the costs for each oxygenate case. None of these costs are considered sensitive to whether the MTBE ban is California only or nationwide though the volumes that can be accessed from the USGC do vary depending on this factor as explained in Section 8.

9.8 SUPPLY CURVES

Combining the CARBOB costs from each region as shown in Section 9.7 with the volumes of CARBOB from each region developed in Section 8 results in the supply curve or supply function for CARBOB from external sources. The CARBOB supply curves resulting from the California only MTBE ban are shown in Table 9.8-1. The CARBOB supply curves for the U.S. wide MTBE ban are shown in Table 9.8-2.

9.9 HOBC COSTS

Based on a review of CARBOB blending as well as refiner discussions, the only high octane blending component (HOBC) likely to be relevant to the market other than oxygenates which are being addressed by ESAI, is alkylate. Alkylate is the most important single component for manufacturing CARBOB and ability to purchase additional alkylate could be important to California refiners seeking to manufacture CARB gasoline within the state in lieu of importing CARBOB from distant regions.

Alkylate supply is limited and can be used either to manufacture CARBOB in distant locations or for direct movements to California. Each barrel of alkylate may go to either of these two alternatives but for any given increment of alkylate, the choices are mutually exclusive. Importing alkylate diminishes the availability of imported CARBOB.

There is no regular published source of alkylate pricing relied upon by industry participants for actual transactions. Alkylate is sold on the basis of a premium to gasoline. The typical premium is eight to ten cents per gallon over regular unleaded gasoline though higher figures are quoted from time to time. This premium includes all processing costs as well as octane credits or debits and refiner margin. For purposes of this study, we have adopted a premium of twelve cents per gallon because we believe that market conditions may tighten in the event of an MTBE ban.

Alkylate must be shipped and handled in a manner very similar to gasoline. We believe that alkylate is more likely to be delivered directly to refineries for blending there rather than through marine terminals. Therefore, the terminaling charge has been omitted from the cost of delivering alkylate. All other transportation costs are the same as those for CARBOB.

Table 9.9-1 shows the buildup of alkylate cost from each region of the world.

9.10 HOBC SUPPLY CURVE

Combining the alkylate availability shown in Section 8 with the alkylate supply costs shown in Table 9.9-1 results in the alkylate supply curves. The supply curves for alkylate are shown for the California only MTBE ban and the U.S. wide MTBE ban on Table 9.10-1.

TABLE 9.10-1
EXTERNAL ALKYLATE SUPPLIES

		California Only MTBE Ban Volumes, B/D		**Nationwide MTBE Ban** Volumes, B/D	
Region	Cost ¢/Gal	Region	Cumulative	Region	Cumulative
Europe	77.0	27,000	27,000	27,000	27,000
Caribbean	78.4	11,000	38,000	11,000	38,000
Latin America	78.1	25,000	63,000	25,000	63,000
Pacific North West	79.7	4,000	67,000	4,000	67,000
Far East	81.4	14,000	81,000	14,000	81,000
U.S. Gulf Coast	81.5	86,000	167,000	43,000	124,000
Middle East	82.1	8,000	175,000	8,000	132,000

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TABLE 9.7-1
CARBOB COST BY REGION -- AVERAGE SUMMER 1997(ETHANOL)
(Cents per Gallon)

	PNW	USGC	Caribbean	Europe	Latin America	Middle East	Far East
Base Gasoline Price	60.9	59.6	59.5	55.3	59.1	58.9	60.5
Processing Cost	4.2	2.0	1.9	2.8	1.7	2.0	2.6
Octane Credit	-0.9	-0.9	-0.9	-0.9	-0.9	-0.9	0.1
Inventory Holding Costs	0.3	0.4	0.4	0.6	0.4	0.4	1.8
Transportation Cost	6.4	9.3	6.4	8.9	6.4	10.6	6.8
Refiner Margin	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Total CIF Cost	72.9	72.5	69.3	68.7	68.8	73.0	73.7

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TABLE 9.7-2
CARBOB COST BY REGION -- AVERAGE SUMMER 1997(ETHANOL WAIVER)
(Cents per Gallon)

	PNW	USGC	Caribbean	Europe	Latin America	Middle East	Far East
Base Gasoline Price	60.9	59.6	59.5	55.3	59.1	58.9	60.5
Processing Cost	3.2	1.3	1.1	2.0	1.1	1.2	2.0
Octane Credit	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-0.5
Inventory Holding Costs	0.3	0.4	0.4	0.6	0.4	0.4	1.8
Transportation Cost	6.4	9.3	6.4	8.9	6.4	10.6	6.8
Refiner Margin	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Total CIF Cost	71.2	71.0	67.8	67.2	67.4	71.5	72.5

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TABLE 9.7-3
CARBOB COST BY REGION -- AVERAGE SUMMER 1997(ETBE)
(Cents per Gallon)

	PNW	USGC	Caribbean	Europe	Latin America	Middle East	Far East
Base Gasoline Price	60.9	59.6	59.5	55.3	59.1	58.9	60.5
Processing Cost	2.8	1.0	1.0	1.8	1.0	1.0	1.8
Octane Credit	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-0.8
Inventory Holding Costs	0.3	0.4	0.4	0.6	0.4	0.4	1.8
Transportation Cost	6.4	9.3	6.4	8.9	6.4	10.6	6.8
Refiner Margin	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Total CIF Cost	70.6	70.6	67.4	66.8	67.1	71.1	72.0

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TABLE 9.7-4
CARBOB COST BY REGION -- AVERAGE SUMMER 1997(TBA)
(Cents per Gallon)

	PNW	USGC	Caribbean	Europe	Latin America	Middle East	Far East
Base Gasoline Price	60.9	59.6	59.5	55.3	59.1	58.9	60.5
Processing Cost	3.3	1.3	1.2	2.1	1.1	1.3	2.0
Octane Credit	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	0.4
Inventory Holding Costs	0.3	0.4	0.4	0.6	0.4	0.4	1.8
Transportation Cost	6.4	9.3	6.4	8.9	6.4	10.6	6.8
Refiner Margin	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Total CIF Cost	72.3	72.0	68.9	68.2	68.4	72.6	73.5

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TABLE 9.7-5
CARBOB COST BY REGION -- AVERAGE SUMMER 1997(MIXED OXYGENATE)
(Cents per Gallon)

	PNW	USGC	Caribbean	Europe	Latin America	Middle East	Far East
Base Gasoline Price	60.9	59.6	59.5	55.3	59.1	58.9	60.5
Processing Cost	3.2	1.3	1.1	2.0	1.1	1.2	2.0
Octane Credit	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-0.2
Inventory Holding Costs	0.3	0.4	0.4	0.6	0.4	0.4	1.8
Transportation Cost	6.4	9.3	6.4	8.9	6.4	10.6	6.8
Refiner Margin	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Total CIF Cost	71.6	71.3	68.2	67.5	67.8	71.9	72.8

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TABLE 9.7-6
CARBOB COST BY REGION -- AVERAGE SUMMER 1997(NO OXYGENATE)
(Cents per Gallon)

	PNW	USGC	Caribbean	Europe	Latin America	Middle East	Far East
Base Gasoline Price	60.9	59.6	59.5	55.3	59.1	58.9	60.5
Processing Cost	3.2	1.3	1.1	2.0	1.1	1.2	2.0
Octane Credit	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Inventory Holding Costs	0.3	0.4	0.4	0.6	0.4	0.4	1.8
Transportation Cost	6.4	9.3	6.4	8.9	6.4	10.6	6.8
Refiner Margin	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Total CIF Cost	72.8	72.6	69.4	68.8	69.0	73.1	73.0

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TABLE 9.8-1
SUPPLY CURVE
EXTERNAL CARBOB SUPPLIES - CALIFORNIA ONLY MTBE BAN

		Ethanol (No Waiver)				Ethanol (Waiver)				Mixed Oxygenates	
	Cost	Volumes, B/D			Cost	Volumes, B/D			Cost	Volumes, B/D	
Region	¢/Gal	Region	Cumulative	Region	¢/Gal	Region	Cumulative	Region	¢/Gal	Region	Cumulative
Europe	68.7	67,000	67,000	Europe	67.2	67,000	67,000	Europe	67.5	148,000	148,000
Latin America	68.8	63,000	130,000	Latin America	67.4	63,000	130,000	Latin America	67.8	63,000	211,000
Caribbean	69.3	26,000	156,000	Caribbean	67.8	26,000	156,000	Caribbean	68.2	26,000	237,000
U.S. Gulf Coast	72.5	214,000	370,000	U.S. Gulf Coast	71.0	214,000	370,000	U.S. Gulf Coast	71.3	470,000	707,000
Pacific North West	72.9	10,000	380,000	Pacific North West	71.2	10,000	380,000	Pacific North West	71.6	14,000	721,000
Middle East	73.0	21,000	401,000	Middle East	71.5	21,000	401,000	Middle East	71.9	21,000	742,000
Far East	73.7	34,000	435,000	Far East	72.5	34,000	435,000	Far East	72.8	34,000	776,000

		TBA				ETBE				No Oxygenates	
	Cost	Volumes, B/D			Cost	Volumes, B/D			Cost	Volumes, B/D	
Region	¢/Gal	Region	Cumulative	Region	¢/Gal	Region	Cumulative	Region	¢/Gal	Region	Cumulative
Europe	68.2	148,000	148,000	Europe	66.8	148,000	148,000	Europe	68.8	67,000	67,000
Latin America	68.4	63,000	211,000	Latin America	67.1	63,000	211,000	Latin America	69.0	63,000	130,000
Caribbean	68.9	26,000	237,000	Caribbean	67.4	26,000	237,000	Caribbean	69.4	26,000	156,000
U.S. Gulf Coast	72.0	470,000	707,000	U.S. Gulf Coast	70.6	470,000	707,000	U.S. Gulf Coast	72.6	214,000	370,000
Pacific North West	72.3	14,000	721,000	Pacific North West	70.6	14,000	721,000	Pacific North West	72.8	10,000	380,000
Middle East	72.6	21,000	742,000	Middle East	71.1	21,000	742,000	Far East	73.0	34,000	414,000
Far East	73.5	34,000	776,000	Far East	72.0	34,000	776,000	Middle East	73.1	21,000	435,000

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TABLE 9.8-2
SUPPLY CURVE
EXTERNAL CARBOB SUPPLIES - US WIDE MTBE BAN

		Ethanol (No Waiver)				Ethanol (Waiver)				Mixed Oxygenates	
	Cost	Volumes, B/D			Cost	Volumes, B/D			Cost	Volumes, B/D	
Region	¢/Gal	Region	Cumulative	Region	¢/Gal	Region	Cumulative	Region	¢/Gal	Region	Cumulative
Europe	68.7	67,000	67,000	Europe	67.2	67,000	67,000	Europe	67.5	148,000	148,000
Latin America	68.8	63,000	130,000	Latin America	67.4	63,000	130,000	Latin America	67.8	63,000	211,000
Caribbean	69.3	26,000	156,000	Caribbean	67.8	26,000	156,000	Caribbean	68.2	26,000	237,000
U.S. Gulf Coast	72.5	107,000	263,000	Pacific North West	71.0	10,000	166,000	Pacific North West	71.3	14,000	251,000
Pacific North West	72.9	10,000	273,000	U.S. Gulf Coast	71.2	107,000	273,000	U.S. Gulf Coast	71.6	235,000	486,000
Middle East	73.0	21,000	294,000	Middle East	71.5	21,000	294,000	Middle East	71.9	21,000	507,000
Far East	73.7	34,000	328,000	Far East	72.5	34,000	328,000	Far East	72.8	34,000	541,000

		TBA				ETBE				No Oxygenates	
	Cost	Volumes, B/D			Cost	Volumes, B/D			Cost	Volumes, B/D	
Region	¢/Gal	Region	Cumulative	Region	¢/Gal	Region	Cumulative	Region	¢/Gal	Region	Cumulative
Europe	68.2	148,000	148,000	Europe	66.8	148,000	148,000	Europe	68.8	67,000	67,000
Latin America	68.4	63,000	211,000	Latin America	67.1	63,000	211,000	Latin America	69.0	63,000	130,000
Caribbean	68.9	26,000	237,000	Caribbean	67.4	26,000	237,000	Caribbean	69.4	26,000	156,000
U.S. Gulf Coast	72.0	235,000	472,000	Pacific North West	70.6	14,000	251,000	Far East	72.6	34,000	190,000
Pacific North West	72.3	14,000	486,000	U.S. Gulf Coast	70.6	235,000	486,000	Pacific North West	72.8	10,000	200,000
Middle East	72.6	21,000	507,000	Middle East	71.1	21,000	507,000	Middle East	73.0	21,000	221,000
Far East	73.5	34,000	541,000	Far East	72.0	34,000	541,000	U.S. Gulf Coast	73.1	107,000	328,000

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TABLE 9.9-1
ALKYLATE SUPPLY COST
(Cents per Gallon)

	PNW	USGC	Caribbean	Europe	Latin America	Middle East	Far East
Base Gasoline Price	60.9	59.6	59.5	55.3	59.1	58.9	60.5
Alkylate Premium	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Inventory Holding Costs	0.3	0.5	0.4	0.8	0.5	0.5	2.1
Transportation Cost	6.5	9.4	6.5	9.0	6.5	10.7	6.8
Total CIF Cost	79.7	81.5	78.4	77.0	78.1	82.1	81.4

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STAFF REPORT

SUPPLY AND COST OF ALTERNATIVES TO MTBE IN GASOLINE

TECHNICAL APPENDICES

Adequacy of Marine Infrastructure

OCTOBER 1998

CALIFORNIA ENERGY COMMISSION

Pete Wilson, ***Governor***

P300-98-013E

ADEQUACY OF MARINE INFRASTRUCTURE

Prepared For:

ACUREX ENVIRONMENTAL CORPORATION

AND

CALIFORNIA ENERGY COMMISSION

Prepared By:

PURVIN & GERTZ, INC.

Dallas - Houston - Los Angeles
Calgary - London
Buenos Aires - Singapore

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John H. Vautrain

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1. INTRODUCTION

1.1 PARTIES

Purvin & Gertz, Inc., (Purvin & Gertz), was retained by Acurex Environmental Corporation (Acurex) on behalf of the California Energy Commission (CEC) to provide evaluations and assistance related to the proposed MTBE ban in California. Purvin & Gertz was retained to provide four deliverables: a presentation at a public workshop, a report on the supply costs of CARB gasoline and blend stocks from outside California, a report on the marine terminal infrastructure and associated limitations, and compilation of the final report combining Purvin & Gertz work with that of other consultants. This document is the report describing the marine infrastructure aspects of an MTBE ban.

This report has been prepared for the sole benefit of the CEC. Any third party in possession of the report may not rely upon its conclusions without the written consent of Purvin & Gertz.

Purvin & Gertz conducted this analysis and prepared this report utilizing reasonable care and skill in applying methods of analysis consistent with normal industry practice. All results are based on information available at the time of review. Changes in factors upon which the review is based could affect the results. Forecasts are inherently uncertain because of events or combinations of events which cannot reasonably be foreseen including the actions of government, individuals, third parties and competitors. ***NO IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE SHALL APPLY.***

Some of the information on which this report is based has been provided by others. Purvin & Gertz has utilized such information without verification unless specifically noted otherwise. Purvin & Gertz accepts no liability for errors or inaccuracies in information provided by others.

Two other consultants, Mathpro, Inc. (Mathpro) and Energy Security Analysis, Inc. (ESAI) are preparing parallel reports on other aspects of the MTBE ban under separate contracts with Acurex. Although the goals of the work are joint, the three consultants, Purvin & Gertz, Mathpro and ESAI, are working independently and none is responsible for the work or results of another. Neither Mathpro nor ESAI is responsible for any results presented in this report.

1.2 PURPOSE AND BACKGROUND

Legislative proposals have been made in California which would ban or restrict the use of MTBE as a gasoline blending component. MTBE is widely used in California as part of refiners' efforts to comply with reformulated gasoline requirements imposed by the U.S. Environmental Protection Agency (EPA) and the California Air Resources Board (CARB). Mathpro is preparing linear program (LP) models of the California refining industry. These models are used to estimate the capabilities of the refineries to produce CARB gasoline

under a variety of scenarios and the capital and operating changes that would be expected to occur in the event that MTBE is banned or restricted under a variety of scenarios. ESAI is identifying the supply costs of various oxygenate alternatives to MTBE. Purvin & Gertz has prepared supply curves for CARBOB supplies from external markets for use by Mathpro. The scope of this study is limited to the adequacy of the marine infrastructure with respect to an MTBE ban. The results of all of the consultants will be combined into an aggregated report.

Policy recommendations regarding the path which should be followed with respect to the MTBE ban or restriction are to be made only by CEC. Purvin & Gertz makes no recommendation in this report whether any particular option is superior to another. Nothing in this report should be construed as making a policy recommendation. CEC is responsible for making any policy recommendations after giving appropriate consideration to the reports of all the consultants as well as to other information as may be deemed appropriate by CEC.

2. SUMMARY AND CONCLUSIONS

Two types of marine infrastructure may be needed to deal with the trade impacts of an MTBE ban: 1) marine terminals and port facilities and 2) marine tankers. Marine terminals and port facilities might be needed to handle both inbound and outbound shipments of a variety of petroleum materials including CARBOB, other finished products such as jet fuel and diesel fuel, unfinished materials or blendstocks such as alkylate, oxygenates such as ethanol, TAME, TBA or ETBE, and high vapor pressure materials such as pentanes or butanes. Marine carriers including both international flag carriers and Jones Act carriers would be needed to transport the cargo materials to and from the port facilities.

Important factors that limit or may limit marine transportation and may impact a ban on MTBE include:

- Insufficiency of the Jones Act fleet, particularly at higher utilization levels
- Inability to load high vapor pressure cargoes such as pentane onto marine carriers
- Unavailability of Jones Act LPG/pentane carriers
- Potential difficulties unloading marine-borne ethanol and transporting to consumption points

There are adequate Jones Act tankers for some volume of shipments from the U.S. Gulf Coast but the availability of such carriers may limit CARBOB deliveries over the intermediate term to volumes substantially below those that might otherwise be available. The scale of the prospective movements of domestic CARBOB to California and the tanker tonnage necessary to support such movements is large when compared to the overall Jones Act fleet. Additional tonnage may be necessary to support high levels of shipments. Over the long term such tonnage could be built if the anticipated need for the movements was of sufficient duration to amortize the costs. In the event that adequate Jones Act tonnage is not available, marine traffic may be directed to otherwise less economic foreign sources or destinations to take advantage of more available international flag carriers.

There is only very limited ability to handle marine cargoes of high vapor pressure materials such as pentanes and butane. There is no dedicated system for pentane. The San Francisco Bay Area lacks any ability to load butane. There is one dedicated LPG facility in the Los Angeles area which can handle some butane cargo volume into tankers. In the event that significant increases in butane shipment or any pentane shipment by marine carriers is anticipated, new facilities would have to be constructed to allow for shipment.

However, pentane is unlikely to be shipped by marine methods. Costs of accessing marine shipping to the U.S. Gulf Coast are excessive and adequate ships are not available. Rail offers the most likely alternative to marine shipping to the U.S. Gulf Coast. Given adequate lead time, marine systems could be developed to ship pentane to overseas markets if this proved economical.

There is not adequate marine infrastructure in place and dedicated to handle large volumes of ethanol imports. Since ethanol would have to be blended with gasoline at pipeline terminals, marine terminals for handling ethanol imports would be required to transship the ethanol to truck or rail carriers for delivery to pipeline terminals around the state. With adequate time, marine terminals could be retrofitted to handle ethanol as needed. It is more likely ethanol would be delivered preferentially by rail or truck from domestic sources.

There is adequate marine terminal and port facility infrastructure to handle a substantial increase in traffic in conventional products and crude oil. Market participants report an ability to handle hundreds of thousands of barrels per day of additional traffic in petroleum products. Refinery capacity for crude oil receiving, combined with that of third party terminals, is considered not to be a factor limiting crude oil throughput at refineries.

There is adequate marine terminal facility to handle imports of oxygenates other than ethanol. Except for ethanol, oxygenate imports would be directed to the refineries where they would be blended. Currently such facilities are used to import MTBE for blending at the refineries for which other oxygenates would substitute.

There are adequate international flag carriers to handle significant volumes of petroleum product shipments to or from California. The scale of such shipments is relatively small by world standards and could be accommodated using existing carriers. There are adequate international carriers to handle any possible increases in butane shipments. It is unclear that there are adequate international flag carriers to handle maximum volumes of pentanes and time might be needed to develop such carriers.

3. BACKGROUND

At the present time the system for delivering petroleum products to California relies mostly on refineries within the state to provide products. There are only very limited volumes of product imports and these arrive most commonly when there is some disruption in the refining system. MTBE routinely is received by marine methods as very little is produced within the state. Transportation of butane and propane mostly is by truck or rail. There is no significant trade in pentane. There are some small movements of pentane-rich streams by rail and truck mostly to and from fractionators located in the San Joaquin Valley. The West Coast often has had excess diesel-type materials that are shipped to foreign markets. There are some coastwise marine movements including movements from the San Francisco Bay area to Southern California and some trade with the Pacific North West and traffic to the Portland market. On the whole, the West Coast is a self-contained market for petroleum products.

Product movements, other than MTBE, from the U.S. Gulf Coast to California are unusual. The cost of marine transportation from the U.S. Gulf Coast is about eight cents per gallon or more. This cost barrier is fairly high when compared to prevailing price differences between the California and Gulf Coast markets. Consequently, it is not practical under normal conditions to transport products from the U.S. Gulf Coast for sale in the California market. Movements from the U.S. Gulf Coast can be attractive only in the case of short term market shortfalls in California. If California prices rise appreciably, more than about eight cents per gallon above the U.S. Gulf Coast, then movements from the U.S. Gulf Coast can and do occur, but only in limited quantities.

Crude oils in California come from the state's own production and from waterborne deliveries. Most of the California crude oil is shipped by pipeline with dwindling volumes moving by marine carriers. California crudes carried by waterborne means are decreasing both because of declining production in certain fields for which there is no other transportation available and also because new pipeline construction is reducing the need for marine shipments. Crude oils from Alaska and foreign sources are delivered by marine tanker directly to refineries and to third party marine terminals in the San Francisco Bay area and the Los Angeles area. The volume of these marine shipments has increased with time as overall refinery crude oil throughput has increased to pace product demand and as California crude production has declined.

Banning MTBE may cause fundamental changes in the relationship between California and markets in other parts of the world. It is possible that refineries may find manufacturing CARB gasoline difficult without MTBE and therefore that California refineries may be unable to manufacture all the products California needs. In that case, the state would become much more dependent on deliveries from other supply areas. Since there are no pipelines bringing petroleum products into California and rail or truck would be prohibitively expensive due to the distances involved, deliveries from other areas would have to arrive by marine carrier. Similarly, banning MTBE may cause refineries to manufacture some products that California does not need or cannot use, such as gasoline that does not

comply with CARB specifications. If that happened, then such products might have to be shipped by marine carriers to other markets. Marine transportation could play an important role in facilitating any needed changes in the relationships between California markets and the rest of the world.

Both tankers and terminals would be needed to handle additional marine traffic. An adequate supply of marine carriers must exist to transport the products to and from California. Adequate marine terminal space must exist to provide shore side handling of the products. A shortfall in either type of capacity would represent a failure of the marine infrastructure.

Nationality or “flag” of marine carriers is relevant to an MTBE ban. First, international flag tankers can carry international shipments. Such shipments can originate in a foreign port and be delivered to a U.S. port or originate in U.S. ports and deliver to foreign ports. Second, Jones Act tankers, which must be both U.S.-flagged and U.S.-built, are the only tankers authorized to carry cargoes originating at one U.S. port for delivery to another U.S. port. The Jones Act is more restrictive than merely preserving domestic waterborne commerce to U.S. flag vessels. U.S. flag vessels that were built in foreign shipyards are not authorized under the Jones Act to transport cargo from one U.S. port to another. There are other less relevant restrictions in the Jones Act as well.

Four different types of products movements have been identified that might be relevant to an MTBE ban. First, receipt of CARBOB or other products like jet fuel or diesel fuel into California might be needed. Second, receipt of ethanol or other oxygenates might be needed. Third, shipment of conventional products such as gasoline might be needed. Fourth, shipment of high vapor pressure components such as pentane or butane might be needed.

In principle an MTBE ban might also increase crude oil requirements at California refineries but this is not considered a significant marine infrastructure problem. Refineries typically have adequate crude oil handling infrastructure so that refinery throughput is limited by factors other than the ability to access waterborne crude oil. Second, there is adequate tanker capacity to handle world crude production. Alaskan production is handled by Jones Act tankers and more Jones Act capacity already is planned or under construction to be able to handle expected Alaskan production. All California production already has adequate transportation. Foreign production would be delivered by international flag tankers. Delivering more international crude oil to California is insignificant compared to existing world movements. Marine infrastructure for crude oil is considered adequate. There will be no further consideration of crude oil marine infrastructure requirements in this report and all further references to marine infrastructure refer to materials other than crude oil.

4. PORT FACILITIES

Marine terminals and port facilities for petroleum products include both refinery marine facilities and third party terminals. Both these types of facilities might be important to responding to an MTBE ban. The roles played by the two types of facilities overlap to some extent but each has its own strengths.

4.1 REFINERY FACILITIES

All major refineries in California have access to waterborne transportation systems but the design of most refinery systems is not optimal for mitigating the impacts of an MTBE ban. Refinery marine facilities for light products tend to be designed for limited volumes and to be oriented mostly for outbound shipments. Refineries as a group are able to handle inbound MTBE shipments. No refinery in California has any capability to load vessels with pentane blends as these exceed normal vapor pressure limitations. Refineries generally lack marine facilities oriented toward ethanol as well.

Refineries typically cannot receive large volume shipments of light products. Refineries mostly are sources of such materials, not destinations, though they typically are able to handle MTBE or small volumes of intermediates like naphtha. Refineries are inadequate to serve as terminals for large volumes of waterborne CARBOB or finished product deliveries.

Refineries typically can load marine vessels with light products or have adequate access to facilities to do so. Light products, particularly gasoline and diesel fuels, have been shipped regularly from California refineries into coastwise and international trade. Refineries' ability to load vessels with volatile light products may be limited by permit restrictions related to air emissions associated with loading marine vessels.

Loading pentane blends at high vapor pressure requires specialized loading equipment that all California refineries lack. Shipping such material is unusual and no refinery has installed the needed equipment yet. Before the introduction of CARB gasoline about two years ago, California refineries typically would not isolate pentane within the refinery or seek to ship it as a product. Because of CARB gasoline's stringent specifications, California refineries now isolate some pentane from gasoline to control vapor pressure below CARB's 7.0 psia limits. Over the past two years some refineries may have experienced containment problems with pentane in the summer but these have been alleviated without resorting to marine shipments. Refinery infrastructure is wholly inadequate for waterborne shipment of pentane.

California refineries typically are unable to ship butane by marine carriers. No California refiner has its own facilities to load butane onto marine carriers. Refineries more typically use rail transportation to handle butane materials. Refinery marine infrastructure for butane loading is inadequate for waterborne shipment of butane.

Waterborne ethanol shipments could pose problems for refineries. Refineries can receive oxygenates but are not prepared to ship oxygenates prior to blending. Refineries typically

can receive MTBE cargoes and regularly do so to blend CARB gasoline. In principle, the same facilities might be used to handle ethanol or other oxygenates. On the other hand, refineries have had little or no need to transfer the neat MTBE onto rail cars or trucks. MTBE has been blended with gasoline at the refinery and shipped as part of finished gasoline in the pipeline network. Only a limited part of the state's need for ethanol would be for use at the refinery and most would be blended with the refinery-produced components of CARB gasoline at the point of truck loading, usually a pipeline terminal. Refineries would blend only as much ethanol as would be consumed by gasoline shipments by truck from the refinery site itself. Refinery infrastructure is inadequate to handle waterborne ethanol shipments except to the extent such shipments would be blended with gasoline at the refinery.

Oxygenates other than ethanol would be used in the same manner as MTBE has been used. MTBE has been received mostly by marine carriers so a system is in place that can be used for alternative oxygenates. Some review of the technical details of each refinery's system may be needed to ensure that all components are suitable for the substitute oxygenate. The oxygenate would be blended with the refinery-produced gasoline components at the refinery to produce finished CARB gasoline in the same general manner as MTBE is. The exact volume of oxygenate that would be used may be different for TBA, TAME or ETBE than it is for MTBE. Hence, the utilization of these facilities may change, however, such a change is not considered likely to be a material problem deterring an MTBE ban.

4.2 THIRD PARTY MARINE TERMINALS

Third party marine terminals also can contribute to handling marine traffic resulting from an MTBE ban. Third party terminals typically are organized differently than refinery systems and often have greater flexibility to handle new patterns of movements.

Third party marine terminals typically are designed to be able to receive large marine shipments of finished light products. An important part of the historical business of such terminals has been in receiving such shipments in time of shortage. Third party marine terminals typically have good pipeline connections allowing shipment of products into the pipeline network. Most areas of the state should be accessible via pipeline transportation to products received via third party marine terminals. Third party marine terminal infrastructure is adequate to handle very large volumes of light products delivered to California.

There is only one third party marine terminal in California with the ability to load butane onto marine carriers. That facility is in the Los Angeles area and is connected to only some of the Los Angeles area refineries. There is no third party marine terminal in the San Francisco Bay area with the ability to load butane onto marine carriers. Third party marine terminal infrastructure is considered inadequate to handle significant increases in waterborne butane shipments.

There is no third party marine terminal in California handling shipments of pentane or high vapor pressure pentane blends. Third party marine terminal infrastructure for pentane

loading is inadequate to contribute to resolution of any further pentane surpluses associated with an MTBE ban.

Third party marine terminals as a group have at best limited rail loading facilities that could be used for ethanol. Third party marine terminals have not been required to transship ethanol from marine carriers to rail cars and do not have facilities in place to do so.

Third party marine terminals have been important in handling MTBE in the past and could contribute to receipts of other oxygenates in the future. To the extent that refineries are unable to handle any volume increases associated with oxygenates such as ETBE or TAME, third party marine terminals are considered able to supplement refinery abilities.

Third party marine terminals are market responsive and have good ability to shift services to accommodate the needs of the marketplace. The terminals historically have accommodated a wide range of transportation and storage needs for petroleum products, MTBE and other materials. The third party terminals generally are able and willing to modify their systems as necessary to meet market demand.

Third party marine terminals require adequate time and incentive to install infrastructure modifications. Third party marine terminals generally require some firm commitment from facility users prior to undertaking expensive modifications. The time needed to complete modifications depends on the scale of the modifications but the time needed for third party terminals to install modifications once the necessary permits are in hand is not likely to be a factor limiting the banning of MTBE.

Third party marine terminals have a large volume of capacity. Terminal utilization is not at an historical high point. There were terminal expansions in recent years to accommodate seasonal MTBE handling and other transient needs that remain in service and which could be used to handle products in the event of an MTBE ban. The capacity of the marine terminal system probably exceeds any reasonable requirement for receipt of products.

A survey was taken of refinery and third party terminal operators to determine the adequacy of the industry infrastructure to respond to any increases in marine shipments or receipts resulting from an MTBE ban. The survey results were compiled by the CEC staff and individual company responses are confidential under the Petroleum Industry Information Reporting Act (PIIRA). Summaries of responses were provided to Purvin & Gertz to support the preparation of this report.

The response to the survey is considered adequate but incomplete. Not all companies responded to all questions and some smaller companies failed to respond. No adjustment of the numerical responses was made and the numbers in this report correspond to summaries of responding companies without compensation to account for the non-responding companies.

With respect to receipts of products, the capacity of the industry is very high and quite under-utilized. Companies reported from 20,000 to over 500,000 barrels per day of receipt capacity. Survey responses indicated that under normal summertime conditions, average

receipts ranged from zero to 20,000 barrels per day at various terminals. The survey indicates that there is very substantial capacity available at marine terminals to receive light products and such capacity is not considered a limiting factor.

4.3 COSTS OF UTILIZATION

The cost of receiving products would be a function of throughput and determined by contractual relationships. The terms of such contracts are highly variable.

The actual costs of operating a third party marine terminal or the marine portion of a refinery system are largely fixed. The variable costs are mostly electricity to run pumps and a small amount of manpower to receive tankers or barges. Hence the per barrel costs incurred by the terminal operator are inversely related to throughput.

Third party terminal facilities can be contracted on a variety of bases. Agreements can be short term or long term. They can call for segregated or community storage.

If a lessee wishes to use a tank for only a short period, for example to receive just one cargo and store it, then the terminal contract will be very short term, typically one month. The costs to the lessee for such a contract would be expected to reflect supply and demand at the time the contract is signed as well as the perception on the part of the lessor of the importance of the contract to the lessee. At times of very high utilization such rates can be quite high, as much as perhaps $1 per barrel per month for marine terminals and even higher rates have been reported at high utilization, landlocked terminal locations. When the utilization of terminals is low, such rates can be quite low, perhaps as low as $0.20 per barrel per month or less.

If a lessee wishes to use a tank for a longer period, perhaps one year, then rates tend to be somewhat less volatile and very high peak prices typically would be avoided.

If a lessee wishes to utilize a tank on a very long term basis, say five to ten years, then the lease rate becomes is capped at a level that is more or less reflective of the cost of building tankage. If the lessor attempts to charge a higher price, then the lessee typically would seek a more competitive quote from some other party able to build a new tank and charge a fair price for its use or build the tank himself. The cost of tankage is dependent on design, size, location and other factors but long term lease rates around one cent per gallon of tank capacity per month are adequate in most locations to pay for new tankage and charges of two cents per gallon of tank capacity per month are above the reasonable range for California.

The costs of using a tank on a long term lease are dependent on utilization. If a tank is filled and emptied on the average once per month, then the costs of a long term lease as described above would be one to two cents per gallon. If the tank is filled and emptied twice per month or “turned” in industry parlance, the terminal operator typically would make a nominal charge for the second turn of the tank, perhaps 0.1-0.2 cents per gallon. Hence the average cost per gallon of product might fall nearly in half in this case. It is in the interest of the tank lessee to utilize the tank highly to reduce his unit cost. On the

other hand, if the tank is turned more quickly, the possibility increases that some delay in either the marine shipments or the pipeline shipments would lead to an outage of product or the ship having to wait for tankage to be available and incurring costly demurrage. For marine deliveries, a tank utilization of two turns per month would be quite high but within the range of commercial experience. A utilization of one turn per month is considered reasonable.

Storage can be either segregated or community with segregated storage costing more than community storage. Segregated storage refers to a separate tank or tanks set aside for the exclusive use of one lessee. Community storage refers to using a single tank or system of tanks for commingling the products of all lessees. The community storage operator has the opportunity to utilize available tank space for additional lessees until the storage is completely utilized while no such opportunity exists for the operator of segregated storage. Consequently, the lessor is likely to charge each lessee less for using community storage than for segregated storage.

There are many variables affecting the per gallon product cost of accessing marine terminals. In light of all these variables and considering the typical costs of utilizing storage, the overhang of capacity in the California market, and the relationship of available handling capacity versus anticipated availability of externally-produced CARBOB, a figure of 0.75 cents per gallon is considered reasonable for evaluating the costs of importing CARBOB. While higher costs could be incurred for some users or over the short term, such costs are considered to be unsustainable over the long term.

5. MARINE CARRIERS

5.1 CONVENTIONAL TANKERS - INTERNATIONAL FLAG

International flag tankers can carry international shipments. Such shipments can originate in a foreign port and deliver to a U.S. port or originate in U.S. ports and deliver to foreign ports. International flag carriers are banned from carrying cargo originating in one U.S. port to another U.S. port. Petroleum shipments to and from the U.S. Virgin Islands are able to use international flag carriers to U.S. ports.

The supply of international flag carriers is very large because of the very large scale of international product movements. Average daily international shipments of naphtha, gasoline, diesel fuel and kerosene total approximately 8 million barrels. The fleet to handle these shipments is very large and there is appreciable seasonal variation in trade in the various petroleum products.

The California share of world demand for light petroleum products is not large. Because the scale of international movements of petroleum products that might result from an MTBE ban is so small compared to total movements and total world demand, the tanker demand that would result is considered unlikely to have a measurable impact on world demand or tanker market conditions.

5.2 CONVENTIONAL TANKERS - JONES ACT

The Jones Act places restrictions on vessels carrying cargo between U.S. ports. Such vessels generally must be U.S.-flagged, U.S.-built, U.S.-manned and U.S.-owned. The supply of such vessels is far smaller than the supply of international-flagged carriers as their costs are higher and these vessels as a group are competitive only within U.S. waters.

As reported by the U.S. Maritime Administration, Office of Ports and Domestic Shipping, there are 90 privately owned Jones Act tankers with a total capacity of 6.9 million deadweight tons. Many of these carriers were built for crude oil service between Alaska and the Lower 48 states. Some are small product carriers used predominantly in the Northeast. Only about half of those 90 tankers are product carriers of greater than 35,000 deadweight ton capacity that might be suitable for carrying products from other U.S. ports to California.

Many of these tankers have specified retirement dates within the next few years. About one quarter of the larger product carriers will be retired by 2002 and more than half will be retired by 2010. The same general pattern is true for crude carriers and as a result, new Jones Act tankers are being planned just to keep an adequate fleet to move Alaskan crude oil. Few or no new product carriers are planned for construction.

The balance between supply and demand for these tankers is not entirely clear since many of the tankers are owned by oil companies for their own use. Tanker transportation is

important to some Northeast markets and tankers for those markets would be unavailable almost regardless of price.

Moving large volumes of petroleum products from the U.S. Gulf Coast area to California could require significant tonnage. A single 30,000 dwt tanker continuously carrying product from the Gulf Coast to California would be able to contribute on average about 8,000 barrels per day to California's supply of petroleum products. That same tanker could, in principle, additionally move a similar volume of surplus, non-CARB products from the West Coast back to Gulf Coast area on a backhaul.

Between 30,000 and 40,000 barrels per day of MTBE is delivered to the West Coast from the Gulf Coast in Jones Act tankers. In the event that the marine delivery of oxygenate from U.S. ports to the West Coast is reduced by an MTBE ban, this volume of gasoline might be substituted without accessing additional tanker capacity. This outcome is considered most likely in ethanol cases in which it is unlikely that domestic marine oxygenate shipments would be significant. In those cases the oxygenate is more likely to be shipped by rail to the pipeline terminals in California. In the cases involving TBA, TAME or ETBE, the marine capacity currently carrying MTBE most likely would be converted to the new oxygenate and would not be available to ship CARBOB or other products.

It is unlikely that large volume movements on the scale of 100,000 to 200,000 barrels per day of gasoline or blendstocks from the U.S. Gulf Coast to California could be accommodated with the existing Jones Act tanker fleet. Shipping 200,000 barrels per day of gasoline from the U.S. Gulf Coast would require about 600,000 tonnes of additional Jones Act tanker capacity even if the MTBE tonnage could be converted to gasoline.

There are domestic barges which can also be used to carry products between U.S. ports. Such barges can be cost effective at reasonable distances. Barges are reasonable to use for coastwise trade between the Pacific Northwest and California but are considered impractical for movements from the Gulf Coast. The availability of these barges and the relatively small volume of CARBOB that might be accessible in the Puget Sound refining system indicates that the marine infrastructure for delivering light products to California from the Puget Sound is adequate.

There is a mismatch between the amount of CARBOB that might be available on the U.S. Gulf Coast and the availability of Jones Act tankers that could transport the product to California. The factor limiting availability of CARBOB is more likely to be tankers than Gulf Coast refining. The Jones Act fleet is inadequate to make sustained, high volume deliveries of light products to California from the U.S. Gulf Coast. The Jones Act tanker infrastructure is inadequate to allow California to access all the products that might be available on the U.S. Gulf Coast.

5.3 HIGH VAPOR PRESSURE CARGO CARRIERS

International shipments of high vapor pressure cargoes such as pentane could be accommodated by the existing fleet of marine carriers. The Jones Act tanker fleet contains only one LPG carrier and would be wholly inadequate to carry more than a nominal

quantity of pentane even if that ship were fully available. To access the high capacity U.S. Gulf Coast market, barges are considered too small and consequently, that market would be unavailable to appreciable pentane shipped by marine methods. Pentane marine cargoes likely would be confined to the international market.

5.4 COSTS TO ACCESS MARINE CARRIERS

"Worldscale" refers to the New Worldwide Tanker Nominal Freight Scale as published annually by the Worldscale Associations of London and New York. The Worldscale schedule provides standardized shipping costs between world petroleum ports and includes consideration of shipping time, typical carriage terms, relevant port and canal fees and the like. Worldscale is widely used to estimate consistent shipping costs for diverse voyages.

Economies of scale favor larger tankers. Large tankers generally are less expensive to operate on a per ton or barrel of cargo basis than smaller tankers because many costs are fixed. Crew size does not increase on a basis proportional to tanker capacity. There are economies of scale in the construction of tankers as well. Because of these various economies of scale, large tankers typically charge less for their service than small tankers. These differences can be related to Worldscale. Very large tankers typically would charge less for a voyage than the standard Worldscale charge for that voyage. Small tankers might charge more than the standard Worldscale charge for the same voyage.

Market conditions affect how much tanker owners charge for voyages. When market conditions are favorable to tanker owners, voyage charges tend to move upward with respect to standard Worldscale costs. When tanker utilization is low, voyage charges tend to fall with respect to standard Worldscale costs.

Since the scale of prospective international shipments to and from the West Coast is small relative to world movements of petroleum products, an MTBE ban is unlikely to affect international market conditions. Consequently, no adjustment to typical tanker costs should be used in analyzing the landed costs of international petroleum products.

Because of Jones Act restrictions, market conditions in the U.S. domestic tanker market do not reflect international supply and demand. Typical costs to deliver products from the U.S. Gulf Coast to the West Coast are reported by market participants at eight cents per gallon or more. Such charges are far higher than international flag carriers would be expected to charge for such a voyage were they allowed to compete in that market based on reports of what they charge for other markets and the standard Worldscale costs.

As discussed above, some volume of products might be transported to California from the U.S. Gulf Coast, particularly in the ethanol cases, without disrupting Jones Act tanker markets. That volume is reflective of the volume of MTBE currently being transported by Jones Act carriers, about 40,000 barrels per day.

For some limited increased volume above the 40,000 barrels per day level, Jones Act tanker markets might continue with small price increases. This increased volume is

estimated at no more than an additional 60,000 barrels per day or a total of 100,000 barrels per day. If long term commitments were made for such volumes, these commitments would mitigate some cost pressure. Tanker owners would be relieved of risk of idle time for their tankers in the California service.

Using the existing Jones Act tanker fleet, regular shipments of products including oxygenates from the U.S. Gulf Coast to California beyond 100,000 barrels per day are considered not feasible. Additional tanker capacity would have to be developed to allow such shipments. Over time the capacity to move such products will diminish unless new tankers are built because of scheduled retirements.

The cost of accessing new Jones Act tankers would depend on size. The most practical and lowest cost transportation would be provided by tankers sized at the maximum that could pass through the Panama Canal, “Panamax” tankers. Tankers larger than this size would need to go around South America which is considered uneconomical.

The least cost transportation would be provided by long term charters for the economic life of new Jones Act Panamax tankers. Under these conditions, the estimate of eight cents per gallon used for existing tankers is thought to be sufficient to make such tankers economic. If smaller tankers or shorter charter terms were used, then higher costs would be needed.

6. REMEDIAL ACTIONS

In the event of inadequacy of marine facilities, there are a number of possible compensatory actions that might be taken. These actions could mitigate the impacts of certain types of inadequacies.

First, receipt of CARBOB or other products like jet fuel or diesel fuel into California might be needed. Second, receipt of ethanol or other oxygenates might be needed. Third, shipment of conventional products such as gasoline might be needed. Fourth, shipment of high vapor pressure components such as pentane or butane might be needed.

6.1 PORT FACILITIES

No remedial actions are anticipated for the receipt of CARBOB or other products like jet fuel or diesel fuel. Existing capacity is considered adequate for any likely volume of receipts.

6.1.1 ETHANOL TRANSSHIPMENT

An infrastructure shortcoming has been identified for the receipt and transshipment of waterborne ethanol. Ethanol might be received by rail or truck rather than marine carrier. Since much of the available ethanol is manufactured within the U.S., such movements may be the least costly means of accessing ethanol in any case. Such movements could be directed to pipeline terminals without transshipment at coastal marine terminals or refineries. Any marine ethanol receipts would be sent preferentially to refineries for their own local blending. To the extent that ethanol transshipment capacity still is needed, third party marine terminals could retrofit given adequate incentive and time to do so. The costs of modifying existing third party marine terminals to transship ethanol would be in the low tens of millions of dollars but would not contribute significantly to the costs of banning MTBE.

6.1.2 PENTANE STORAGE/LOADING

A port infrastructure shortcoming has been identified for the shipment of high vapor pressure components such as pentane. This shortfall might be mitigated by diverting the shipments to domestic destinations served by rail or truck. Some regional storage of high vapor pressure components might allow the components to be utilized in the less restrictive winter period. Finally pentanes might be burned as a fuel rather than shipped.

Facilities to handle pentanes could be upgraded at some sites by making capital improvements to refineries and/or terminals. The capital costs of upgrading facilities to be able to load pentane onto marine carriers has been estimated at $2 million to $4 million per site. This cost is not considered material to a decision to ban MTBE.

Pentane storage capacity may be needed to facilitate pentane loading activities. Survey responses ranged from zero (capacity not needed) to a high of $125 per barrel of capacity.

Based on pentane's physical characteristics and the various types of tankage that may be employed in its storage, the upper end of the range of estimates is considered unreasonably high and a range of $30 to 50 per barrel is considered a reasonable estimate. The cost of installing adequate tankage to support loading pressurized vessels for pentane transport may be as high as $20 million per site. This cost level may be high enough to discourage use of marine transportation methods for pentane unless consolidated storage and loading sites could be developed.

6.2 MARINE CARRIERS

No infrastructure shortfall has been identified with respect to international flag carriers.

6.2.1 JONES ACT TANKERS

A possible shortfall of Jones Act tankers has been identified. A number of actions might be taken to mitigate such a shortfall.

Otherwise less attractive international destinations or origins might supplant U.S. destinations or origins to mitigate a Jones Act carrier shortfall.

Pipeline systems could be reconfigured to reduce the need for domestic marine shipments. The capital cost of reconfiguring such systems might be quite high and would have to be supported by a reliable long term need for such shipments.

6.2.1.1 TIME REQUIREMENT FOR JONES ACT TANKER DEVELOPMENT

Significant time would be needed to build more Jones Act tankers. The time to develop more Jones Act carriers can be split into three parts. First, time would be to develop the required commitments to use the carriers. Second, time would be needed to access shipyards to build the carriers. Third, time would be needed to complete construction and enter the carriers into service.

Tankers are expensive to build and would not be built unless there is a good prospect that they would be needed long enough to amortize their costs. In the event that the California refineries ultimately would retrofit to manufacture adequate CARB gasoline without MTBE and the requirement for external gasoline supplies would be for only a short time, such commitments could not be made and the tankers would not be built. Assuming that the outcome of an MTBE ban is that a long term need for tanker transportation would exist, a reasonable period of time, estimated at six months to one year, would be needed for the refining industry to study alternatives and make commitments to new tankers.

There are only a limited number of shipyards within the U.S. capable of constructing tankers. Jones Act tankers must be constructed by these shipyards. The U.S. shipyards have other commitments and would not be able to divert their resources immediately to construction of new Jones Act carriers to deliver U.S. Gulf Coast gasoline to California. An allowance of one to two years should be made to allow the shipyards to begin work on new tankers.

Once construction is begun on a new tanker, the construction time is approximately 24 to 30 months.

The total time from the time an MTBE ban is announced until new Jones Act tankers could be available is estimated at three and a half to five years at least and could be longer if a large number of tankers were required.

6.2.1.2 PIPELINE ALTERNATIVES

No products pipeline proposal that could mitigate a shortfall of Jones Act tankers has been identified at this time. The development of such a proposal lies entirely in the future.

Costs of a pipeline alternative cannot be estimated without detailed knowledge of the volumes to be shipped, their origin, and how such a pipeline proposal would fit into the existing pipeline infrastructure in the Southwestern U.S. There is no assurance that a pipeline alternative would be cost competitive with marine tankers or that prospective shippers would support such an alternative.

The time to develop a pipeline alternative, assuming that an economic alternative could be developed, is similar to the time to build new Jones Act tankers. An allowance of a six months to one year would be needed for the California refining industry to establish that a need exists. Three to four years are likely to be needed to identify an economic pipeline alternative, acquire needed rights of way and permits, acquire shipper commitments, finance and build the line.

STAFF REPORT

SUPPLY AND COST OF ALTERNATIVES TO MTBE IN GASOLINE

TECHNICAL APPENDICES

Impacts of External Markets

OCTOBER 1998

CALIFORNIA ENERGY COMMISSION

Pete Wilson, *Governor*

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IMPACTS ON EXTERNAL MARKETS

Prepared For:

ACUREX ENVIRONMENTAL CORPORATION
AND
CALIFORNIA ENERGY COMMISSION

Prepared By:

P

Dallas - Houston - Los Angeles
Calgary - London
Buenos Aires - Singapore

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John H. Vautrain

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1. INTRODUCTION

1.1 PARTIES

Acurex Environmental Corporation (Acurex) retained Purvin & Gertz, Inc., (Purvin & Gertz), on behalf of the California Energy Commission (CEC) to provide evaluations and assistance related to the proposed MTBE ban in California. Purvin & Gertz was retained to provide four deliverables: a presentation at a public workshop, a report on the supply costs of CARB gasoline and blend stocks from outside California, a report on the marine terminal infrastructure and associated limitations, a report on the external market impacts of an MTBE ban and compilation of the final report combining Purvin & Gertz work with that of other consultants. This document is the report describing the external market impact aspects of an MTBE ban.

This report has been prepared for the sole benefit of the CEC. Any third party in possession of the report may not rely upon its conclusions without the written consent of Purvin & Gertz.

Purvin & Gertz conducted this analysis and prepared this report utilizing reasonable care and skill in applying methods of analysis consistent with normal industry practice. All results are based on information available at the time of review. Changes in factors upon which the review is based could affect the results. Forecasts are inherently uncertain because of events or combinations of events that cannot reasonably be foreseen including the actions of government, individuals, third parties and competitors. ***NO IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE SHALL APPLY.***

Others have provided some of the information on which this report is based. Purvin & Gertz has utilized such information without verification unless specifically noted otherwise. Purvin & Gertz accepts no liability for errors or inaccuracies in information provided by others.

Two other consultants, Mathpro, Inc. (Mathpro) and Energy Security Analysis, Inc. (ESAI) are preparing parallel reports on other aspects of the MTBE ban under separate contracts with Acurex. Although the goals of the work are joint, the three consultants, Purvin & Gertz, Mathpro and ESAI are working independently and none is responsible for the work or results of another. Neither Mathpro nor ESAI is responsible for any results presented in this report.

1.2 PURPOSE AND BACKGROUND

Legislative proposals have been made in California that would ban or restrict the use of MTBE as a gasoline blending component. MTBE is widely used in California as part of refiners' efforts to comply with reformulated gasoline requirements imposed by the U.S. Environmental Protection Agency (EPA) and the California Air Resources Board (CARB). Mathpro is preparing linear program (LP) models of the California refining industry. These models are used to estimate the capabilities of the refineries to produce CARB gasoline under a variety of scenarios and the capital and operating changes that would be expected to occur in the event that MTBE is banned or restricted under a variety of scenarios. ESAI is identifying the supply costs of various oxygenate alternatives to MTBE. Purvin & Gertz has prepared supply curves for CARBOB supplies from external markets for use by Mathpro. The scope of this study is limited to the impacts on external markets of an MTBE ban. The results of all of the consultants will be combined into an aggregated report.

Policy recommendations regarding the path that should be followed with respect to the MTBE ban or restriction are to be made only by CEC. Purvin & Gertz makes no recommendation in this report whether any particular option is superior to another. Nothing in this report should be construed as making a policy recommendation. CEC is responsible for making any policy recommendations after giving appropriate consideration to the reports of all the consultants as well as to other information as may be deemed appropriate by CEC.

2. BASIC PETROLEUM PRICE SET

A set of crude oil and petroleum product prices was developed for use in the CEC analysis. These prices were used in the studies of all the consultants in order to ensure a consistent analysis. Prices for the U.S. Gulf Coast and U.S. West Coast are shown in Table 2-1.

These prices are representative of May through September 1997 market conditions and reflect actual prices witnessed during this time period. This time period was chosen for the study because it was the most recent set of prices representing the summer blending season, a time period when gasoline is in shortest supply and is most difficult to manufacture due to strict RVP restrictions.

The price relationships that are inherent in these numbers, particularly between individual products and between the West Coast and Gulf Coast markets, are simply the price relationships that were witnessed during the summer of 1997. They may or may not be representative of future price relationships or even an historical average. Price relationships of this type tend to vary, both seasonally and year on year, and depend upon the particular market conditions prevailing at the time. Any particular price relationship that is observed in this data cannot be relied upon to prevail during future time periods.

Prices were developed by reference to a variety of price reporting services and represent actual sales transactions that took place. They are based on spot transactions. Sales that occurred on a contract basis would not be represented by this data set. Crude oil posted prices also would not be represented by this data set. Furthermore, these prices represent the price of petroleum products at the refinery gate. There is no marketing or distribution cost or margin associated with them.

TABLE 2-1
CRUDE AND PRODUCT PRICING
May to August 1997

	May-97	Jun-97	Jul-97	Aug-97	Average
Crude (Dollars per Barrel)					
WTI, Cushing	20.90	19.27	19.62	19.92	19.93
Dubai, FOB	18.52	17.25	17.31	17.70	17.70
West Coast Crude					
Line 63, Delivered Hynes Station	18.36	16.30	16.52	16.85	17.01
Thums, Field	16.51	15.23	14.89	15.85	15.62
Kern River, FOB San Joaquin Valley Pipeline Station	14.59	13.50	13.51	14.66	14.07
ANS, Delivered West Coast	19.39	17.28	17.46	17.96	18.03
Products (Cents per Gallon unless Noted)					
Los Angeles					
Butane	26.60	29.00	28.40	30.44	28.61
Isobutane	54.82	55.00	52.80	48.75	52.82
Propane	33.90	32.63	33.30	37.00	34.22
Conv. Unleaded	60.39	53.39	55.08	73.83	60.73
CARB Unleaded	63.01	55.50	58.38	77.71	63.72
Conv. Premium	68.08	59.29	61.97	81.24	67.71
CARB Premium	67.50	59.50	62.39	82.25	67.98
Jet	59.44	56.42	55.10	58.63	57.41
Low Sulfur Diesel	55.58	53.79	51.73	57.68	54.70
CARB Diesel	61.51	58.33	56.40	67.40	60.93
HSFO 3% $/Bbl	14.86	14.40	14.34	14.77	14.59
USGC					
Unleaded	60.61	54.95	58.48	64.45	59.66
RFG Unleaded	62.56	56.65	61.81	67.67	62.22
Midgrade	62.04	56.85	60.38	66.45	61.46
RFG Midgrade	64.12	58.50	63.67	69.79	64.06
Premium	64.85	60.19	64.08	70.56	64.96
RFG Premium	67.01	61.90	67.33	73.57	67.50
Jet	54.73	52.13	53.49	55.69	54.02
High Sulfur Diesel	53.40	50.13	50.95	52.23	51.69
Low Sulfur Diesel	54.14	50.69	51.80	52.94	52.41
No. 6, 3% S, $/Bbl	14.06	13.89	14.32	15.53	14.45
MTBE	77.05	80.62	92.55	91.20	85.39
Methanol	59.40	61.38	64.30	59.80	61.22

Note: All petroleum product prices are spot refinery gate.

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3. IMPACTS ON FEDERAL RFG

3.1 ORIGINS OF IMPACTS

CARBOB or other gasoline blendstocks supplied to California markets in response to an MTBE ban in principle could have an influence on the price of gasoline in the region supplying the fuel. As fuel is drawn from a particular region to supply the shortfall in the California market, supplies in that region will diminish. Such diminished supplies may or may not have an impact on price depending on the regional supply/demand balance and the capability of the domestic refiners.

If the region normally excesses product to other regions, diminished supplies are likely to have little impact on the local price. These excess supplies would be shifted from the original destination to the California market.

If however the region is fairly well balanced, volumes that move to California will need to be replaced. Volumes can either be replaced by imports from another region or by increasing the output of the local refineries. If local refineries have enough excess capacity to make up the shortfall without too much difficulty a substantial price impact is unlikely to be seen.

If supplies are required from other regions though, the price could rise. The actual price rise will depend upon the cost to import the additional supplies. In some cases, imported supplies will cost no more than the prevailing prices, particularly if the region was already reliant on some volume of imports. In this case no substantial price increase will be seen. However, if the region becomes an importer for the first time, it is very likely that imported supplies will cost more than the prevailing price and prices in the region will rise as a result.

3.2 FEDERAL RFG MANUFACTURING

Federal reformulated gasoline (RFG) is manufactured at most large refineries east of the Rockies and in some foreign countries. Nationwide, Federal RFG accounts for more than 1.6 million barrels per day, or nearly 20% of all gasoline sold. Gulf Coast refineries produce more than 42% of the Federal RFG that is consumed in the U.S. Additional volumes are produced in PADDs I and II and are imported from Europe. Federal RFG manufacturing refineries rely heavily on alkylation and isomerization processes to meet these specifications. Since PADD III refiners produce only 18% of their gasoline as Federal RFG, however, these units are not heavily loaded just for Federal RFG. Much of the isomerate and alkylate in PADD III is used to manufacture conventional gasoline.

3.3 IMPACT OF U.S. GULF COAST REFINERIES MANUFACTURING CARBOB

No substantial price impact is expected on the U.S. Gulf Coast as a result of refineries manufacturing CARBOB for the California market. With respect to the discussion of Section 3.1, the Gulf Coast market can be classified as a region with surplus gasoline production capacity and large volumes are exported out of the Gulf Coast to other parts of the U.S.

Gulf Coast refineries manufacture approximately 3.4 million B/D of gasoline. Approximately 1.3 million B/D of this production is consumed locally while the remaining 2.1 million B/D is shipped to other parts of the U.S. PADD I, which stretches from Florida up along the East Coast to Vermont, receives about 1.6 million B/D from Gulf Coast refineries. PADD II, the mid-Western region of the U.S., receives an additional 0.5 million B/D from the Gulf Coast.

Given the large amount of gasoline that currently moves out of the Gulf Coast, it is highly unlikely that movements of CARBOB from the Gulf Coast to California will have any significant impact on prices in either the Gulf Coast market or PADDs I or II. This presumes that the volumes shipped to California are on the order of those discussed in our earlier report.

The most likely outcome of Gulf Coast refineries manufacturing CARBOB is for imports into the northeastern U.S. from Europe to increase to replace the Gulf Coast supplies that are diverted to California. The northeastern U.S. currently imports some 300,000 B/D of gasoline and additional volumes are thought to be readily available. In addition, since the region relies on imported European volumes already, higher imports are unlikely to raise the prevailing price of gasoline in the region.

PADD II will likely continue to receive supplies from the Gulf Coast at the prevailing prices.

3.4 IMPACT OF PROVIDING ALKYLATE ON FEDERAL RFG COSTS

Providing alkylate to the California market either as a blending component or as a component of CARBOB would have a negligible impact on Federal RFG production costs, providing the volume is within the range specified by our report entitled “External CARB Gasoline Supply”.

Alkylate production capacity at the Gulf Coast is fairly high, averaging 545,000 B/D or about 16% of Gulf Coast gasoline production capacity. As a result, alkylate is used in all gasoline grades from Premium RFG to Conventional Regular. Although most of the alkylate used in Premium RFG is required to meet RFG specifications, a significant portion of the alkylate used in the Regular RFG and conventional grades is surplus and is not strictly required to meet specifications.

The basic premise of our earlier report that specifies the available volume of alkylate from the U.S. Gulf Coast is that only alkylate that is in excess of the volume required to meet either RFG or conventional specifications can be diverted to the California market. This volume of alkylate is fairly low valued since it can be diverted out of the Gulf Coast market without impacting the capabilities of refiners to blend their existing set of gasoline grades. Therefore removal of this alkylate in the volumes specified by our report is not expected to result in any increase in the price or value of alkylate on the Gulf Coast, nor result in any increased cost in the manufacture of reformulated gasoline.

4. PRICE ALPHAS FOR BY-PRODUCTS AND BLENDSTOCKS

4.1 DEFINITION OF PRICE ALPHAS

A price alpha is defined as the difference between the price of one commodity and that of another commodity. Price alphas often are used to estimate the prices of petroleum products for which no standard quotations exist. This would include intermediates that are manufactured within the refinery and are seldom traded. It would also include specialized products that are not manufactured or purchased by a large number of entities. Any product that is not traded often enough to warrant reporting by the price reporting services may be valued relative to more standard products using a price alpha.

Price alphas can change with changing market conditions. As with other petroleum product relationships, the price alpha can vary both seasonally or year on year. The price alphas that were estimated for the summer of 1997 for important refinery by-products and blendstocks were based on the relationships observed during that time period and may not represent future or even historical price alphas.

The price alphas that were developed for the CEC analysis were estimated consistent with the basic price set used in the CEC analysis.

4.2 RELEVANT BY-PRODUCTS AND BLENDSTOCKS

Price alphas were estimated for the following by-products and blendstocks:

- Alkylate
- Isomerate
- Pentane
- Light Coker Naphtha
- Light FCC Gasoline
- Heavy FCC Gasoline
- Heavy Reformate

Both isomerate and alkylate are high quality gasoline blendstocks that are often required to produce CARB gasoline. Pentane is a gasoline blending component that may be in excess due to its high vapor pressure. Light coker naphtha, FCC gasoline, and heavy reformate are fairly low quality gasoline blending components with various contaminants that are often difficult to blend into CARB gasoline.

4.3 PREVAILING AND EXPECTED PRICE ALPHAS

The price of alkylate was discussed in some detail in our report entitled “External CARB Gasoline Supply” and will not be further discussed here.

The remaining gasoline components were priced relative to gasoline based on their blending value in the pool. The price alpha for each was thus its estimated value during the summer 1997 time period relative to the price of CARB gasoline during that same time period.

The value of isomerate was determined in a manner similar to that of alkylate. The value of pentane was based on its value in the Gulf Coast market. The value of the rejected gasoline components was based on their value in alternative markets.

STAFF REPORT

SUPPLY AND COST OF ALTERNATIVES TO MTBE IN GASOLINE

TECHNICAL APPENDICES

Refinery Modeling Task 1:
Specifying Scenarios and Methodology

OCTOBER 1998

CALIFORNIA
ENERGY
COMMISSION

Pete Wilson, ***Governor***

P300-98-013G

Evaluating the Cost and Supply of Alternatives to MTBE in California's Reformulated Gasoline

Project Report

REFINERY MODELING

TASK 1: SPECIFYING SCENARIOS AND METHODOLOGY

Prepared for

California Energy Commission

by

MathPro Inc.

under

Subcontract No. CM6006W3

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MathPro Inc.

P.O. Box 34404
West Bethesda, Maryland 20827-0404
301-951-9006

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1. INTRODUCTION

MathPro Inc. is pleased to submit to the California Energy Commission (CEC) this report covering work performed for CEC under Subcontract CM6006W3 (Contract 500-96-012).

This subcontract covers the Refinery Modeling activity in CEC's larger project to evaluate the cost and supply of alternatives to MTBE in California's reformulated gasoline. The primary purpose of the Refinery Modeling activity is to estimate the economic effects on the California refining sector (e.g., incremental operating costs, new capital investments, etc.) of the proposed ban on MTBE in all gasoline consumed in California (referred to here as CARB RFG). The economic effects are to be estimated by formal modeling of the California refining sector, with an established computer-based refinery modeling system (employing *linear programming* (LP), an optimization technique widely used to analyze refining economics). The refinery modeling system of choice is **ARMS**, a proprietary product of MathPro Inc.

The Refinery Modeling activity comprises three tasks:

- **Task 1** Specify the policy scenarios analyzed and the methodology used in the Refinery Modeling activity

- **Task 2** Calibrate the refinery model used in this activity, to conform to aggregate operations of the California refining sector in the 1997 Summer season

- **Task 3** Analyze the specified scenarios using the calibrated refinery model

The primary work product of each task is a project report.

This report covers Task 1. It comprises six sections, including this one.

Section 2 defines important terminology and lays out the various *policy scenarios*.

Section 3 discusses key elements of the *refinery modeling methodology*.

Section 4 discusses *data requirements* for the refinery modeling and indicates the sources of the required data.

Section 5 discusses the *attributes that make LP the method of choice* for analyzing refining economics in studies such as this one.

Section 6 offers a *brief description of the refinery modeling system* used in this study.

The appendix is a copy of the survey questionnaire sent by CEC to California refiners as part of the data gathering process.

2. SCENARIOS TO BE ANALYZED

This section defines essential terminology regarding scenarios to be analyzed in this study and specifies the individual reference and policy scenarios to be analyzed.

2.1 DEFINITIONS

The *reference scenarios* denote (i) business-as-usual in the California refining sector – that is, continued MTBE use in the future time periods of interest, consistent with relevant federal and California laws and regulations now in effect (and with no new laws or regulations that affect MTBE use) – and (ii) business-as-usual, but with HR 630 (the Bilbray bill) in place. (HR 630 is under consideration in the U.S. Congress. Its effects are described below).

Each *policy scenario* denotes a specific set of assumptions regarding possible legislative or regulatory actions that would affect the economics of replacing MTBE.

Analyzing each policy scenario involves a set of refinery modeling runs, or *cases*, where each case corresponds to a unique combination of (1) a *replacement oxygenate* and (2) a *time period.*

A *replacement oxygenate* is a particular oxygenate that could replace MTBE in CARB RFG, chosen from this set:

- Ethanol
- ETBE
- TBA (tertiary butyl alcohol)
- Mixed refinery-produced oxygenates (in proportions determined by the refinery modeling)

Candidates for inclusion in the mixed refinery-produced oxygenates stream are ETBE, TAME, TBA, DIPE, and higher mixed ethers, e.g., as produced by the Neste Oy NeXTAME® process.

The reference and policy scenarios cover two time periods: *intermediate-term* and *long-term.*

- *Intermediate-term* is the earliest time period in which the refining industry could end MTBE use with short-lead-time measures such as de-bottlenecking, retro-fitting, and changes in service in refining, blending, oil movement, and distribution facilities.

  The intermediate term is the time period in which the supply of the given replacement oxygenate reaches a new equilibrium state that supports the additional demand induced by the proposed ban on MTBE in CARB RFG. (Thus, the calendar time period marking the intermediate term may differ from one replacement oxygenate to another.)

- *Long-term* is the earliest time period in which the refining industry could end MTBE use with long-lead-time and possibly large-scale capital investments (e.g., new process capacity) in refining, blending, oil movement, and distribution oxygenate facilities.

  The long term is the time period in which the refining sector completes its response to the proposed ban on MTBE use – through investment in new facilities – and reaches a stable new configuration.

Analyzing each policy scenario – corresponding to a specific set of assumptions regarding possible legislative or regulatory actions – calls for processing up to eight cases with ARMS (the refinery LP modeling system): *four replacement oxygenates* in each of *two time periods*.

2.2 POLICY ASSUMPTIONS

Each policy scenario denotes a unique combination of an *MTBE ban* assumption and an *oxygenate policy* assumption. CEC has specified two MTBE ban and six oxygenate policy assumptions.

- **MTBE Ban**

  - *California Ban on MTBE*

    California bans MTBE use in CARB RFG.

  - *Federal Ban on MTBE*

    In addition, the federal government bans MTBE use throughout the USA, in both conventional gasoline (CG) and reformulated gasoline (RFG).

- **Oxygenate Policy**

  Current Laws and Regulations

  Existing California and federal laws and regulations pertaining to gasoline manufacture remain in effect; but no additional ones.

  HR 630 in Effect

  Congress passes HR 630, ending the federal mandate for oxygenate in gasoline supplied to the federal non-attainment regions in California. Consequently, refiners may produce CARB RFG with oxygen content as low as zero in the Summer season, throughout the state.

  ♦

  Ethanol Rvp Waiver

Gasoline containing 10 vol% ethanol (3.5 wt% oxygen) enjoys a 1 psi Rvp waiver – that is, such gasoline may have an Rvp 1 psi higher than the Rvp standard otherwise applicable. In particular, the ethanol Rvp waiver changes the Rvp standard to ≤ 8.0 psi for CARB RFG containing 10 vol% ethanol.

No Tax Credits for Ethanol or ETBE

The existing federal tax credits granted to refiners and blenders of gasoline containing ethanol or ETBE are not extended after they expire in 2000.

No Tax Credits & HR 630

The existing federal tax credits described above expire and HR 630 passes.

No Tax Credits & Ethanol Rvp Waiver

The existing federal tax credits described above expire and ethanol enjoys the 1 psi Rvp waiver in California or throughout the USA (depending on the primary policy assumption in a given scenario).

Thus, for example, one policy scenario denotes the combination *California Ban on MTBE* and *Current Laws and Regulations*; another denotes *Federal Ban on MTBE* and *Current Laws and Regulations*; a third denotes *California Ban on MTBE* and *HR 630 in Effect*; and so on.

2.3 REFERENCE AND POLICY SCENARIOS

Exhibit 1 (next page) lists the reference and policy scenarios covered in the Refinery Modeling activity. In Exhibit 1, each line denotes a policy scenario, and each **X** denotes a specific replacement oxygenate for the indicated scenario.

As Exhibit 1 indicates, the Refinery Modeling activity encompasses two (2) reference scenarios, twelve (12) policy scenarios, and a total of seventy six (76) cases (refinery model runs).

2.4 PRIMARY RESULTS OF THE ANALYSIS

From the analysis of the various reference and policy cases, we will generate – for each policy scenario – intermediate term and long term estimates of:

- *Incremental costs*, including refinery operating and ancillary costs, refinery capital costs, import costs, and the social cost of changes in fuel economy associated with each replacement oxygenate;

- *Refining sector investments* for additional process capacity required with each

replacement oxygenate;

- *Refining sector utilization*, in terms of crude runs and production volumes of refined products meeting California standards; and

- *Average properties* of the CARB RFG and conventional gasoline pools produced in the California refineries, including (i) the gasoline properties registered in the CARB Predictive Model, (ii) Driveability Index (DI), and (iii) energy content.

These estimates will constitute the primary results of the Refinery Modeling activity.

Exhibit 1: Reference and Policy Scenarios for Refinery Modeling

		Replacement Oxygenates				
Scenarios		MTBE	EtOH	ETBE	TBA	MRE
Reference Assumptions						
	Business as Usual (MTBE Use)	X				
	Business as Usual & HR 630 in Effect	X				
Policy Assumptions						
California Ban on MTBE	Current Laws and Regulations		X	X	X	X
	HR 630 in Effect		X	X	X	X
	Ethanol Rvp Waiver		X			
	No Tax Credits for EtOH or ETBE		X	X		X
	No Tax Credits and HR 630 in Effect		X	X		X
	No Tax Credits and EtOH Rvp Waiver		X	X		X
Federal Ban on MTBE	Current Laws and Regulations		X	X	X	X
	HR 630 in Effect		X	X	X	X
	Ethanol Rvp Waiver		X			
	No Tax Credits for EtOH or ETBE		X	X		X
	No Tax Credits and HR 630 in Effect		X	X		X
	No Tax Credits and EtOH Rvp Waiver		X	X		X

3. REFINERY MODELING METHODOLOGY

This section provides a brief overview of the refinery modeling methodology for Task 2 (calibration) and Task 3 (analysis of scenarios) of the Refinery Modeling activity. The section covers five topics.

1. Focus on the Summer season
2. Modeling California refineries with an aggregated model
3. Sequence of analytical steps in the methodology
4. Balancing domestic production, imports, and exports
5. Computing primary results of the analysis

3.1 FOCUS ON THE SUMMER SEASON

All of the refinery modeling runs in Tasks 2 and 3 apply to the Summer gasoline season only (May through August). In any given refinery, Summer gasoline is more costly to produce and requires more intensive use of capital stock than Winter gasoline. Any technical constraints on a given refinery's gasoline-making capability are most severe in the Summer season. In particular, the production cost and volume implications of replacing MTBE in CARB gasoline would be more severe in the Summer than in the Winter.

> The primary cause of the seasonal effect on refining economics is the gasoline Rvp standard, which is lower (more stringent) in the Summer than in the Winter.

3.2 MODELING AGGREGATE REFINING CAPACITY

Exhibit 2 lists the California refineries represented in the Refinery Modeling activity. These thirteen refineries account for more than 93% of the crude oil processing capacity in the California refining sector and virtually all capacity for producing CARB RFG.

The methodology for Tasks 2 and 3 employs a custom-developed representation (within the ARMS modeling system) of the aggregate refining process capacity of the refineries listed in Exhibit 2. (For brevity, we use the term **CALAGG** to denote this aggregate of California refining capacity.) Within ARMS, CALAGG refining capacity appears as one "aggregate refinery". The aggregate refinery is a model; it represents a single refinery that

- runs a crude oil slate matching the aggregate crude oil slate actually run in CALAGG;
- produces a product slate with volumes and properties consistent with current or forecast production in CALAGG; and
- has a process unit capacity profile and average process capabilities corresponding to those in CALAGG.

Exhibit 2: California Refineries Represented

Company	Location	Capacity (K Bbl/day)
ARCO Products Co.	Carson	255
Chevron USA Products Co.	El Segundo	258
	Richmond	225
Exxon Co. USA	Benicia	128
Kern Oil & Refining Co.	Bakersfield	21.4
Mobil Oil Corp.	Torrance	130
Shell Martinez Refining Co.	Martinez	155.2
Texaco Refining & Marketing	Bakersfield	57.8
	Wilmington	91.7
Tosco Refining Co.	Avon	156
	Rodeo/Santa Maria	103.6
	Wilmington	118.8
Ultramar Diamond Shamrock	Wilmington	68
Total		**1768.5**

Note: **Capacity** refers to crude oil charge rate.

One can think of an aggregate refinery as a representation of totally coordinated operation of the individual refineries in the specified refining sector (in this instance, CALAGG). In this idealized situation, refineries trade intermediate refinery streams, blendstocks, and products so as to make optimal use of all refining capacity, process by process, regardless of the refinery(s) in which the processing capacity resides.

Considerable trading of this kind actually occurs, but in volumes limited by physical and institutional barriers and by the capabilities of the capital stock in place. That is, an aggregate refinery represents inter-refinery trading beyond what can actually take place.

Consequently, results of analyses using an aggregate refinery model tend to indicate somewhat higher aggregate profit contributions and/or lower production costs and capital investments than actually would occur for a given set of market conditions and regulatory requirements. This tendency is one form of a modeling phenomenon known as "over-optimization". Over-optimization is characteristic of all analysis of refining operations that involves modeling aggregate refining capacity.

Good modeling practice can limit the effects of over-optimization and produce useful results for planning and policy recommendations. Indeed, refinery LP models representing large aggregates of refining process capacity (such as CALAGG) have been used to support development of all federal standards for motor fuels and have yielded prior estimates of average refining costs reasonably close to the industry's average realized costs.

Use of an aggregate refinery model – as opposed to modeling each individual refinery or regional refining center – is dictated by the funding and time available for the Refining Modeling activity. However, analysis with the CALAGG aggregate model should provide a good indication of the average incremental costs and volume effects of banning MTBE use and of the *relative* costs – state-wide – of replacing MTBE under the various policy scenarios.

More disaggregated modeling would yield more detailed (and perhaps more valid) estimates of the costs associated with MTBE replacement.

> For example, an individual refinery would have its own unique cost of producing CARB RFG without MTBE in any given scenario. That cost would depend, in part, on the refinery's own capital stock, operating requirements, and product slate.

3.3 FOUR STEP METHODOLOGY

Our technical approach, or methodology, for the refinery modeling analysis comprises four steps:

- in Task 2

1. Develop the aggregate refinery representation of CALAGG.

2. Calibrate ARMS so that the aggregate refinery conforms to key aspects of reported CALAGG operations in the 1997 Summer season.

- in Task 3

3. Develop and analyze the Reference Scenario cases, representing CALAGG operations under the two reference scenarios defined in Exhibit 1.

4. Develop and analyze the Policy Scenario cases, representing CALAGG operations under the twelve policy scenarios defined in Exhibit 1.

Following is a brief discussion of each step.

3.3.1 Represent the Aggregate Refinery in ARMS

Using the ARMS database, data in published sources, and data collected by CEC from the California refineries, we will establish the CALAGG aggregate refinery in ARMS.

The aggregate refinery will reflect CALAGG operations reported for the 1997 Summer season – including aggregate refining process capacities (by process unit), capacity utilization (by process unit), crude oil slate, product slate, gasoline grade splits, Class B and C gasoline splits, prices for crude oil and refined products, product specifications, and average properties of the CARB RFG and conventional gasoline pools produced by California refineries.

3.3.2 Calibrate ARMS to Summer 1997 Operations

Calibration demonstrates the validity, for the study at hand, of the ARMS refinery LP model and derives certain technical data elements for use in the subsequent steps.

Calibration involves adjusting technical data elements (e.g., gasoline blendstock properties, process yields and stream qualities, process unit capacity factors, etc.) in the ARMS database such that the ARMS model yields solution values that match with sufficient precision certain key measures of refinery operations in the calibration period (Summer 1997, in this instance). Once we accomplish this matching, we “freeze” the data elements for the subsequent steps.

Key measures for the calibration include reported product volumes, purchased blendstock volumes, gasoline pool composition, and capacity utilization of various refining processes. In this study, calibration will also focus on certain average properties of the CARB RFG and CG pools produced during the 1997 Summer season:

- Sulfur content
- Benzene content
- Oxygen content
- The T_{50} temperature in the gasoline distillation curve
- The T_{90} temperature in the gasoline distillation curve

These gasoline pool properties are independent variables in the CARB Predictive Model, which estimates vehicle emissions of NOx, VOC, and toxics, as functions of gasoline properties.

3.3.3 Analyze Reference Cases

The reference cases – representing business-as-usual operations in the Summer season in the intermediate term and long term periods – define the baseline for the subsequent analysis of the policy cases. Results of the reference case analysis constitute estimates of baseline refinery operations, product out-turns, and costs. Comparison of these baseline values with corresponding values generated in the analysis of policy scenarios provides estimates of the costs and technical implications of the various policy scenarios. In analyzing the reference cases, we will

- use the same slate of crude oils as the CALAGG refineries processed in Summer 1997; and

- use the CARB Predictive Model to calculate the emission reductions of gasoline pools produced by the aggregate refinery.

The reference cases will incorporate forecasts provided by CEC of the demand for refined products in California (and in the portions of adjoining states now served by California refineries) in the intermediate term and long term time periods.

3.3.4 Analyze the Policy Cases

The policy cases, defined in Exhibit 1, represent CALAGG operations under each policy scenario (for each indicated combination of time period and replacement oxygenate). In analyzing the policy cases, we will

- use a 15% rate of return on investment in computing the magnitude of capital investment in new process capacity and a 10% rate of return on investment in computing the per barrel costs of capital recovery;

- increase the capital charge factors for new process capacity needed to meet Summer, but not Winter, standards, such that Summer operations alone recover all capital charges (capital recovery and return on capital);

- use the same slate of crude oils as the CALAGG refineries processed in Summer 1997;

- use the CARB Predictive Model to calculate the emission reductions of gasoline pools produced by the aggregate refinery; and

- assume no price elasticity of demand for refined products.

In addition, we will assume that the refining sector's response to a ban on MTBE would involve an optimal combination of (i) advanced processing techniques with existing process capacity and (ii) investments in new process capacity using process technology now in commercial use or being offered for commercial use.

Most of the policy scenarios are neutral with respect to air quality, because they entail conforming to existing standards. But the scenarios involving the ethanol Rvp waiver produce an adverse effect on air quality, because VOC emissions increase with increasing Rvp. For these scenarios, the magnitude of the air quality degradation stemming from the ethanol Rvp waiver will be estimated as part of the overall CEC study, but not within the Refinery Modeling activity.

3.4 BALANCING PRODUCTION, IMPORTS, AND EXPORTS OF REFINED PRODUCTS

The analysis of the policy cases will accommodate – but not require – certain prospective changes in CALAGG operations:

- Reduced crude runs (relative to the Summer 1997 crude run);
- Reduced product out-turns (relative to the Summer 1997 out-turn);
- Imports of refined products (e.g., CARB RFG, diesel fuel, etc.) or blendstocks, to the extent economic or necessary (because of technical constraints in CALAGG) to meet forecast demand for CARB RFG and (perhaps) other products; and
- Exports of refined products or unfinished oils ("distressed cargoes"), to the extent economic or necessary to comply with a ban on MTBE use while meeting all other California product specifications.

This is an important aspect of the refinery modeling methodology, and it merits some discussion. CEC and other close observers of the California refining sector have expressed concern that a ban on MTBE use would not only increase the *cost* of producing CARB RFG but also reduce the total *volume* of CARB RFG that California refiners could produce (while meeting existing product specifications and environmental standards).

Any shortfall in California production of CARB RFG would have to be made up by imports of CARB RFG[1] (from the U.S. Gulf Coast or offshore sources). At the same time, technical and economic considerations might lead California refiners to export some volumes of refinery streams or finished products, such as pentanes and/or gasoline not meeting CARB standards. In this situation, the economics of CARB RFG supply would be determined by the interplay between the aggregate cost structure of the California

[1] In this context, we use CARB RFG to denote either CARB gasoline itself or any "CARBOB". A CARBOB is a base non-oxygenated gasoline, which may be blended with a specific oxygenate to produce on-spec CARB RFG.

refineries, the price-volume relationships for imported CARB RFG and various refinery inputs, and the cost-volume relationships for exported refinery outputs.

We address this possibility explicitly in the refinery modeling work. Specifically, the ARMS model will represent not only the aggregate refinery but also

- *Imports* of CARB RFG and/or gasoline blendstocks (alkylate, raffinate, and reformate);

- *Exports* of conventional gasoline and/or pentanes.

Solutions to the extended model will indicate (i) shortfalls (if any) in domestic (in-state) production of CARB RFG; (ii) volumes of all in-state production, imports (if any), and exports (if any); and (iii) market-clearing marginal costs of gasoline and other refined products.

Extending the aggregate refinery model in this way takes the analysis beyond the realm of conventional refinery modeling.

Exhibit 3 summarizes this aspect of the methodology. As the exhibit indicates, certain supply functions and demand functions are part of the input to the extended aggregate refinery model in ARMS. The supply functions for the replacement oxygenates are being developed by the Oxygenates Availability activity of the CEC project. The other supply functions and the demand functions are being developed in the California Import Capability activity.

3.5 COMPUTING PRIMARY RESULTS OF THE ANALYSIS

The primary results of the analysis comprise, for each policy case, the following elements:

- Incremental Costs (¢/gal)
  - Refinery operating costs (variable, or direct, refining costs)
  - Refinery capital charges (capital recovery and return on investment)
  - Import costs (for imported gasoline, other products, blendstocks, and refinery inputs)
  - Refinery ancillary costs (storage, blending, oil movement costs)
  - Fuel economy (mileage) change

- Refining Sector Investment ($MM) – for new process capacity

- Refining Sector Utilization (Bbl/day)
  - Domestic (California) production of gasoline, diesel, and other products
  - Domestic crude runs

- Average Gasoline Pool Properties
  - CARB Predictive Model properties
  - Driveability index
  - Energy Density

Exhibit 3: Balancing In-State Production, Imports, and Exports

For each policy case,

- ARMS inputs include
  - Forecasts of in-state and out-of-state demand for refined products (from CEC)
  - Estimated price-volume relationships (*"supply functions"*) for imported gasoline, replacement oxygenate, and specified gasoline blendstocks (alkylate, raffinate, reformate)
  - Estimated cost-volume relationships (*"demand functions"*) for exported conventional gasoline and refinery excess streams (pentanes)
- ARMS computes economic optimal solution, depicting the equilibrium between in-state production, imports, and exports of refined products
- ARMS outputs include
-
  - Capacity utilization in the California refineries
  - Volumes of CARB RFG and other refined products produced by California refineries
  - Volumes of imported streams (by type)
  - Volumes of exported streams (by type)
  - Market-clearing marginal costs of CARB RFG and other products

Following are brief comments on the computation of results from the outputs generated by ARMS for the reference and policy cases.

3.5.1 Incremental Costs

For each policy case, the total incremental costs (per gallon) of removing MTBE from CARB RFG is the sum of the four cost elements listed above. In turn, each of these cost elements is the *difference* between the estimated costs of (i) producing CARB RFG without MTBE, with the given policy scenario and replacement oxygenate, and (ii) producing CARB RFG under the corresponding reference scenario.

All of these costs are in cents per gallon of CARB RFG. The costs are *time-specific*; they apply to the Summer season of the indicated time period.

Refinery operating costs are the per-gallon variable, or direct, costs registered in the aggregate refinery (e.g., crude oil and unfinished oils, purchased utilities, catalysts and chemicals, etc.).

Refinery capital charges are the per-gallon costs registered in the aggregate refinery for recovery of capital invested in new process capacity, with a 10% rate of return.

Import costs are the costs of imports of CARB RFG and gasoline blendstocks (net of revenues from exports of conventional gasoline and other refinery outputs).

Refinery ancillary costs denote costs that California refineries would likely occur in complying with a ban on MTBE use but that are not registered in a refinery LP model. These costs could include capital charges for incremental tankage, inventory, and blending facilities, and associated operating expenses. The reported values for ancillary costs are our estimates, which are based on prior discussions with people in the refining refinery.

Mileage loss is the cost to California consumers of the difference in fuel economy (average miles/gallon) between CARB RFG produced without MTBE (policy case) and with MTBE (reference case).

A gasoline's fuel economy is proportional to its energy density (expressed in MM BTU/Bbl or in M BTU/gal). Physical considerations dictate that energy density decreases with increasing oxygen content, decreasing distillation temperatures (i.e., T_{50} and T_{90}), and increasing RVP.

ARMS captures all of these effects, and computes the energy density (in MM BTU/Bbl) of each gasoline pool, along with the pool's Predictive Model properties.

We use the following formula to estimate the cost *to California consumers* of mileage losses indicated in the policy cases:

$$\Delta \text{ Fuel economy cost (¢/gal)} = \Delta \text{ ED (\%)} * [\text{ARP (¢/gal)} + \text{IRC (¢/gal)}]$$

where

Δ ED is the change in energy density with respect to the reference gasoline pool, expressed as a percentage of the energy density of the reference gasoline pool;

ARP is the adjusted average retail price of gasoline in California (*excluding* federal and state taxes) – to be provided by CEC for the Summer 1997 season; and

IRC is the incremental refinery operating cost and capital charge in the given case.

This formula is consistent with EPA's approach in assessing the costs of the federal RFG program.

3.5.2 Refining Sector Investment

Refining sector investment denotes capital investments in the CALAGG refineries for new process units and expansions of existing units. They correspond to solution values registered for the aggregate refinery and include on-site and off-site elements.

3.5.3 Refining Sector Utilization

Refining sector utilization encompasses several measures of the extent to which existing California refining capacity would remain employed in the face of a ban on MTBE use. The measures – crude runs in California refineries and production in California refineries of gasoline (CARB RFG and conventional), diesel fuel, and other products – correspond to values registered in the aggregate refinery.

3.5.4 Gasoline Properties

The gasoline properties reported for each policy case are absolute, not incremental, values. ARMS produces all of these values directly, except for DI. We estimate DI for each case using the distillation curve computed by ARMS for that case and the following formula for DI:

$$DI = 1.5 \times T_{10} + 3.0 \times T_{50} + T_{90}$$

Txx denotes the temperature (^{o}F) at which xx vol% of the gasoline evaporates in the standard laboratory distillation test.

4. DATA FOR REFINERY MODELING

This section deals with the data requirements for the refinery modeling described in Sections 2 and 3. The discussion covers three topics.

1. Data classes
2. Data sources
3. Special survey of California refiners

4.1 CLASSES OF DATA

Refinery modeling draws upon two broad classes of data (i.e., numerical values that characterize refinery operations).

Techno-economic values describe (in engineering terms) (i) refinery inputs and outputs (e.g., crude oils, refined products), process unit capacity, and the economics of capital investment; and (ii) the performance of individual refining processes, in terms of input/output coefficients (e.g., process yields, energy consumption, etc.), refinery stream properties, and blendstock qualities.
Techno-economic values may be refinery-specific, or they may represent region-wide (as in this study) or industry-wide averages.

> ARMS contains a set of representative techno-economic values, including all elements needed to create the CALAGG aggregate refinery. Some of these elements will be modified in the calibration step (Task 2), as described in Section 3.3. After calibration, we will "freeze" the resulting set of techno-economic values for the subsequent analysis of the reference and policy cases (Task 3).

Boundary values denote external conditions that refining operations must satisfy in a given location and time period, such as crude oil availabilities, product demands, product specifications, crude and product prices, and environmental standards.[2] For prior time periods (e.g., Summer 1997, the calibration period), boundary values usually denote "real" values, drawn from published reports on refining operations. For future time periods (e.g., the intermediate term and long term periods), boundary values are explicit forecasts. (In this context, the estimated supply functions and demand functions discussed in Section 3.4 and Exhibit 3 are boundary values.)

> In developing and calibrating the aggregate refinery model, we will use boundary values for the Summer 1997 period that are aggregated across all CALAGG refineries and averaged over the four months of the period. No refinery-specific values will be employed in the refinery modeling analysis.

[2] We call these "boundary values" because they characterize streams that flow into or out of the refinery, i.e., across the refinery's boundaries.

CEC will derive the aggregated and averaged boundary values for the Summer 1997 period from (i) standard monthly reports submitted by the refineries (e.g., CEC M07, EIA 810) and (ii) the returns from a special survey of California refineries conducted for this study (discussed in Section 4.3).

In analyzing the reference and policy cases, we will use boundary values for the intermediate term and long term periods that incorporate (i) forecasts of California demand for CARB RFG and other refined products and (ii) estimated supply functions and demand functions for imported and exported streams, respectively. These boundary values will be the *only* inputs to the aggregate refinery model that are unique to the reference and policy cases.

4.2 DATA SOURCES

Data required for the refinery modeling analysis will come from six main sources:

1. The existing ARMS database;

2. Publications (e.g., the annual world-wide refining surveys of the *Oil & Gas Journal*; the annual *Oil & Gas Databooks*; the *Petroleum Supply Annual*, *Annual Energy Review*, and *Annual Energy Outlook*, all published by the U.S. Energy Information Administration (EIA), etc.);

3. Standard monthly reports submitted by California refiners to CEC (e.g.; CEC M07) and EIA (e.g., EIA 810) for the calibration period (Summer 1997);

4. A special one-off survey of California refineries regarding Summer 1997 operations, conducted by CEC for this study;

5. Forecasts, developed by CEC, of (i) California demand for CARB RFG and other refined products and (ii) out-of-state demand for conventional gasoline and other refined products, in the intermediate term and long term periods; and

6. Estimated supply functions and demand functions for specified import and export streams, developed in the Oxygenates Availability and California Import Capability activities

Exhibit 4 (next page) indicates the data sources that come into play in each step of the refinery modeling methodology, described in Section 3.3. (The numbers in the heading of Exhibit 4 correspond to the items above.)

Exhibit 4: Data Sources for the Refinery Modeling Methodology

		Data Source					
Methodology	**Data Values**	1	2	3	4	5	6
1. Develop Aggregate	Techno-Economic	X	X		X		
Refinery Model	Boundary	X	X	X			
2. Calibrate Aggregate	Techno-Economic	X			X		
Refinery Model	Boundary	X		X			
3. Analyze Reference Cases	Techno-Economic	X					
	Boundary	X				X	
4. Analyze Policy Cases	Techno-Economic	X					
	Boundary	X				X	X

4.3 SPECIAL SURVEY OF CALIFORNIA REFINERIES

As noted in Section 4.1, CEC has conducted a special survey of California refineries to support development and calibration of the aggregate refinery model. The survey sought techno-economic and boundary value data on actual refinery operations for the four months of the Summer 1997 season. All thirteen CALAGG refineries participated in the survey.

The survey employed a questionnaire designed by CEC and MathPro Inc. A copy of the questionnaire is appended to this report.

CEC will analyze the survey returns and convey the survey results aggregated across all refineries and averaged over the four month period.

CEC is treating the individual survey returns as confidential. CEC will not provide refinery-specific to the Refining Modeling activity.

5. LP AS THE METHOD OF CHOICE FOR REFINERY MODELING

This section explains why linear programming is the method of choice for the Refinery Modeling activity and, indeed, for most techno-economic analyses of refining operations.

5.1 TECHNO-ECONOMIC ANALYSIS AND LINEAR PROGRAMMING

Analyzing the economics of gasoline production – including (for example) the prospective costs of producing CARB RFG without using MTBE – calls for engineering (or *techno-economic*) analysis of the specific refinery or aggregate refinery of interest. Since the late '50s, the method of choice for conducting techno-economic analysis of refining operations has been formal, computer-based modeling with a *refinery LP model*.

> LP is the most widely used mathematical technique for optimization – that is, for finding the best solution (in an economic sense) to complex problems involving allocation of scarce resources across many competing activities.
>
> In refining operations, the scarce resources are the refinery's production facilities, raw materials, and process streams (e.g., blendstocks), and the competing activities are the refinery's manifold processing operations.

Virtually all refining companies use in-house, custom-configured LP models of their own refineries for (i) tactical and operations planning, (ii) monthly and weekly scheduling, and (iii) crude oil and product pricing analysis. Government agencies and private sector organizations use generalized refinery LP models (that can be adapted to represent specific refineries or refinery groupings) to estimate the effects on refining economics of proposed policies, regulations, and fuel standards.

5.2 LP'S UNIQUE VALUE FOR REFINERY MODELING

LP is indispensable for refinery modeling because:

- It embodies rigorous, robust, and efficient search procedures, which find the best solution from the set of all possible solutions to the case at hand.

- Results generated by an LP model contain two distinct but complementary classes of information -- *physical* (e.g., levels of activity for various processing options, flow rates, blend compositions, etc.) and *economic* (e.g., marginal prices, penalty costs, substitution rates, etc.).

  In this respect, LP stands alone. No other analytical method generates results of comparable breadth, depth, and analytical value.

- Powerful, reliable off-the-shelf software is available for most LP applications.

These attributes have important implications for analysis. First, LP modeling provides a rigorous means of comparing solutions to different scenarios, or cases. Because LP generates optimal solutions, one can compare solutions for different cases knowing that each solution is computed "to the hilt" in the same rigorous manner and is the best for the given case. Second, LP modeling both demands and facilitates simultaneous consideration of the economic and physical aspects of the problem at hand.

5.3 INFORMATION GENERATED BY A REFINERY LP MODEL

With a refinery LP model, experienced analysts can simulate how a refinery or group of refineries would operate – on an average day in a specified time period – to produce a specified product slate at minimum cost. These simulations yield not only descriptions of prospective refinery operations but also

- the total and marginal *refining costs* associated with the case at hand;
- *capital investment requirements* and *operational changes* called for by the case at hand;
- *properties* of the gasolines (and other refined products produced), for calculating emissions and other kinds of performance (e.g., fuel economy); and
- *marginal refining values* (or "*shadow prices*") for all refinery streams, including both internally produced and purchased blendstocks.

Solutions to sequences of LP modeling cases can trace out refinery supply functions and indicate the impacts on refining operations and economics of prospective changes in energy and environmental policy and regulation; crude oil and feedstock quality, price, and availability; product demand and specifications; and refining capital stock.

6. OVERVIEW OF ARMS

ARMS is a generalized refinery modeling system, developed by MathPro Inc. This section introduces ARMS. The discussion – very brief – covers four topics.

1. Applications
2. Main technical features
3. Basic modeling concepts
4. Special features

6.1 APPLICATIONS OF ARMS

ARMS is an established refinery modeling system, with a track record of use in numerous projects for private companies and government agencies, covering a range of issues including:

- Refining costs, investment requirements, and environmental performance of alternative gasoline formulations considered by the Ozone Transport Assessment Group (OTAG), chartered by EPA to recommend measures for improving air quality in the Ozone Transport Region of the U.S.;

- Refining costs, investment requirements, and environmental performance of alternative gasoline formulations for Maricopa County, Arizona, in support of the state's implementation plan for ozone control;

- Refining costs associated with reducing the sulfur content of conventional and reformulated gasolines to very low levels;
-
- Refining values of and prospective demands for ethanol as direct gasoline blendstock or oxygenate feedstock;

- Refining values of purchased gasoline blendstocks (including MTBE and other oxygenates), by region, refinery type, and season;

- Refining costs of producing reformulated gasolines to various regulatory standards and requirements in the U.S., Canada, and other countries;

- Refining economics of generating tradeable emissions credits by producing gasolines whose emissions performance exceeds regulatory requirements;

- Refining economics of lead phase-down and phase-out in various countries;

- Refining economics of producing additional volumes of petrochemical feeds;

- Economic impacts on the refining sector of new process technologies;

- Effects of changes in gasoline composition on refinery energy requirements;
- Refining values (in the U.S. and other countries) of various domestic and foreign crude oils (including crude blends in the Strategic Petroleum Reserve);
- Refining values of Alaskan North Slope (ANS) crude to Pacific Rim refiners (for the federal policy review that led to repeal of the ban on exporting ANS crude); and
- Effects on U.S. oil imports and refining economics of prospective octane-enhancing additives (e.g., MMT) for gasoline blending.

Some of these studies have made important contributions to the understanding of the economic effects of public policy initiatives affecting the refining sector.

6.2 TECHNICAL SUMMARY

ARMS is a PC-resident refinery modeling system. It is designed specifically to support policy analysis and business planning studies dealing with technical and economic responses of the refining industry (or individual refineries) to real or prospective changes in public policy, regulation, technology, and/or market conditions. Consistent with its purpose, ARMS represents the technology and economics of refinery operations in **engineering** (not econometric) terms.

ARMS comprises a linear programming (LP) model of refining operations; a library of crude oil assays; a database of techno-economic values describing refinery operations; and software for creating, operating, and reporting on refinery LP models.

> The LP model is expressed as a computer-readable **model statement**, specifying the model's mathematics and logic in symbolic form, independent of any data one might associate with the model and embody in its coefficients. The database contains techno-economic and boundary values, in tabular or relational form.

Linking the model statement to a specific set of techno-economic and boundary values produces a distinct **model instance**, or **case**, that ARMS processes and solves. (Typical analyses of policy and planning issues may involve creating and processing hundreds of cases.)

ARMS has custom-designed computer programs for managing the model statement; managing data; creating model instances (cases); solving models; and analyzing model solutions. The programs form an open, flexible, easy-to-enhance system, with links to spreadsheets and other external applications. By virtue of this design and implementation approach, ARMS supports both quick response analyses and longer-term analyses that call for modifying or extending the model statement (as in this study).

ARMS operates under Windows 95® and is implemented by means of fourth-generation optimization modeling software (an advanced modeling toolkit and a high-speed solver).

6.3 BASIC MODELING CONCEPTS

The ARMS LP model is a *static*, *process-oriented*, *disaggregated*, *optimizing* representation of the operations and economics of refining.

- *Optimizing*: Solutions to the LP model define optimal refining operations and economics for the specified refinery or refining aggregate and policy scenario.

- *Disaggregated*: ARMS represents refining facilities (that is, capital stock within refinery battery limits) at a user-specified level of disaggregation: an individual PADD or a group of PADDs (e.g., PADDs 1-3), a state, a group of similar refineries in a region or refining center (e.g., complex refineries in the Los Angeles center), or an individual refinery.

- *Process-oriented*: ARMS represents refining operations, process by process, in techno-economic or engineering (not econometric) terms.

- *Static*: ARMS represents an average day's operations of the specified refining aggregate or refinery in the specified time period (year and season), with no inter-temporal flows such as inventory build-up or draw-down.

The solution to an ARMS case defines a pattern of refining operations and a set of prices for feeds, products, and refinery process capacity that minimize aggregate refining cost or maximize aggregate profit contribution, for a given set of boundary values.

In this context, *profit contribution* is the difference

Product Revenues - Costs of (Crude + Other Inputs + Purchased Energy + Catalysts/Chemicals) - Investment Amortization

where the revenues and all of the cost items are per barrel of output and input (respectively), with fixed costs not considered.

The ARMS LP model is a partial equilibrium model. That is, the solution to an ARMS case simulates refining operations such that

- the market for each refined product clears at the computed prices;

- each refinery is in competition with all others in the given region; and

- all competitors have full information about the market.

Solutions to a given ARMS case define optimal refining operations in terms of:

- volumes consumed and marginal value of crude oils and purchased blendstocks;
- compositions and qualities of finished products blended to specification;
- aggregate capacity utilization and the marginal value of new capacity, by process;
- aggregate investment in new capacity;
- volumes produced and marginal cost of each finished product;
- marginal cost of each intermediate refinery stream and blendstock; and
- marginal cost of satisfying each individual specification, by blended product.

6.4 SPECIAL FEATURES

6.4.1 Process Representations

ARMS contains representations of not only the standard commercial refining processes but also prospective new processes and process options. Some of the new technologies are for producing oxygenates, oxygenated and reformulated gasolines, and low-sulfur gasolines and diesel fuels; others are for improving refining economics in general. Examples include olefin-maximizing FCC catalysts, FCC operations with residual oil feeds, depentanization of gasoline blendstocks, hydrotreating FCC gasoline via the OCTGAIN® process, and "under-cutting" FCC gasolines and reformates.

Because fluid catalytic cracking (FCC) operations are the most important single determinant of refining economics in conversion refineries and because FCC units have exceptional flexibility, ARMS contains an especially detailed representation of FCC operations. The representation covers various feedstocks (ranging from distillates to residual oils), catalyst types, operating modes, and conversion levels.

ARMS allows representations of three distinct gasoline pools – e.g., CARB RFG, federal Phase 2 RFG, and conventional (as in this study). Each pool may contain up to three gasoline grades (e.g., regular, mid-grade, and premium). ARMS honors specifications for each grade and for each pool represented.

6.4.2 Predictive Model and Complex Model Representations

ARMS contains built-in representations of (i) the federal Phase 2 Complex Model for certifying federal RFG and (ii) the California Predictive Model for certifying CARB RFG. Consequently, in ARMS solutions, the properties of the RFG pools (if any) comply with the

relevant (federal or California) emission standards. We use the Predictive Model representation in this study.

Following is a brief overview of our procedure for building the Complex Model (CM) and the Predictive Model (PM) into ARMS.

First, we derived reduced form representations of the CM and the PM, in separated form.

> A *reduced form* model captures in simple mathematical structure the main input/output relationships of a larger, more complicated model, with sufficient accuracy for the analytical purpose at hand.
>
> A model in *separated* form comprises only single-variable functions. That is, none of the model's terms involve more than one independent variable – no cross products, quotients, etc. In this sense, the variables are separated.

The reduced form models for the CM and PM are sets of polynomial equations of the form:

$$ER_i = a_i + \Sigma_j (b_{ij}X_j + c_{ij}X_j^2)$$

Where **i** = emission category [VOC (total), NOx, Toxics]

j = gasoline property [Rvp, oxygen content, aromatics content, benzene content, olefins content, sulfur content, E200, E300]

ER_i = Emission reduction, category **i**

a_i = Constant term for emission category i

b_{ij} and c_{ij} = Coefficients of the first order and second order terms for emission category **i** and gasoline property **j**

Xj = Value of gasoline property **j** (computed in the LP model)

Estimating the reduced form models was itself a three-step procedure. We generated sets of 4,000 random gasoline "blends" (i.e., random combinations of the gasoline properties), for each reduced form model. (We imposed no functional relationships or constraints to restrict the random combinations of gasoline properties to "feasible" gasoline blends.) Then, for each of the 4,000 random blends in each set, we used the "real" CM or PM (as appropriate) to calculate the corresponding emissions changes. Finally, we used standard regression analysis to estimate second order polynomial equations relating calculated emission changes to gasoline properties. (The estimated equations have $R^2 > 0.99$, meaning that they explain about 99% of the blend-to-blend variations in emission reductions.)

Second, we embedded the reduced form CM and PM models in the ARMS LP model.

Having the reduced form models in separated form is the key to this step. The reduced form models are nonlinear in the gasoline properties. But because they are separated, one can express them directly in LP's linear framework – as sets of *piece-wise-linear* functions, one for each gasoline property involved. In LP parlance, piece-wise-linear functions are called *Special Ordered Sets, Type 2* (**SOS2**).

We expressed the nonlinear reduced form equations for the CM and the PM as two discrete sets of SOS2s (one set for the CM; one for the PM) and added these functions to the ARMS refinery LP model.

We solve the refinery LP model containing the CM or PM using a commercial solver with SOS2 capability.

This discussion touches only on the highlights of the approach. Discussion of the details, some of which are of critical importance, is beyond the scope of this report. A full discussion is in *Fuel Reformulation*, Vol. 4, No. 2; March/April 1994; pgs 64-68.

APPENDIX

SPECIMEN SURVEY OF CALIFORNIA REFINERIES

Refinery Location:

Company:

Table 1: Process Unit Capacity and Capacity Utilization: Summer 1997

Process Type/ Flow Diag. Unit Name	Unit	Capacity in Terms of	Maximum Sustainable Capacity* (bbl/sd)	Actual Throughput** (bbl/sd)	Process Information	Notes
Crude Dist.						
	Atmospheric	Feed				
	Vacuum	Feed				
Conversion						
	Visbreaking	Feed				
	Coking	Feed				(1)
	Thermal Cracking	Feed				
	Fluid Cat Cracking	Feed				(2)
	Hydrocracking	Feed				(3)
Upgrading						
	Alkylation (HF or SA)	Product				
	Reforming #1	Feed				(4)
	#2	Feed				(4)
	C5/C6 Isomerization	Feed				(5)
	Dimer	Product				
	Polymerization	Product				
H2 Generation						
	Refinery-owned	Prod. (K scf/d)				(6)
	Captive, 3rd party-owned	Prod. (K scf/d)				(7)
	Other (purchases)	(K scf/d)				(8)
Hydrogen	Purification	Feed (K scf/d)				(9)
Oxy. Prod.						
	MTBE	Product				
	TAME	Product				

Refinery Location:

Company:

Table 1: Process Unit Capacity and Capacity Utilization: Summer 1997

Process Type/ Flow Diag. Unit Name	Unit	Capacity in Terms of	Maximum Sustainable Capacity* (bbl/sd)	Actual Throughput** (bbl/sd)	Process Information	Notes
Hydrotreating						
	LSR Naphtha	Feed				
	Reformer Feed	Feed				
	Distillate Desulfurization	Feed				
	Distillate Dearomatization	Feed				
	FCC Feed/Heavy Gas Oil	Feed				
	Resid	Feed				
	FCC Gasoline	Feed				
	Benzene Saturation	Feed				
	Other	Feed				
Other						
	Solvent Deasphalting	Feed				(10)
	Sulfur Recovery	Product				(11)
	Tail Gas Recovery	Product				
	Lube Oil	Product				
	C4 Isomerization	Feed				
	Aromatics Production	Product				
	Cogeneration	MegW				
	Other					

* Maximum sustainable daily capacity over the summer months, given quality of feeds.

** Average throughput for Summer 1997.

Notes:

(1) Indicate delayed, fluid, or flexi coking.

(2) Provide average conversion rate in percent.

(3) Provide hydrogen consumption in K scf/bbl of feed and operating pressure in psig.

(4) Provide unit pressure (psi) and average severity (RON).

(5) Indicate if recycle or once-through. Capacity should include internal recycle and recycle volume from downstream seperation units.

(6) Include capacity only of refinery-owned units. Report capacity in terms of K scf/d of hydrogen product.

(7) Provide capacity of third-party owned hydrogen units that are fully dedicated to your refinery.

(8) Provide average daily purchases of hydrogen from sources other than company-owned and dedicated third-party units.

(9) Include only if purification plant is a system separate from the hydrogen plant and is used for other streams. Capacity should be reported in terms of K scf/d of feed. Indicate purified hydrogen output as a percent of the volume of input streams.

(10) Report capacity in terms of long tons of product sulfur from sulfur plant.

(11) Report capacity in terms of long tons of product sulfur from tail gas unit only.

Refinery Location:

Company:

Table 2: Typical Feeds, by Unit: Summer 1997

Process Type/ Flow Diag. Unit Name	Unit	Typical Feeds					
		Boiling Range (°F) or Description	% of Charge	Boiling Range (°F) or Description	% of Charge	Boiling Range (°F) or Description	% of Charge
Conversion							
	Visbreaking						
	Coking						
	Thermal Cracking						
	Fluid Cat Cracking						
	Hydrocracking						
Upgrading							
	Alkylation (HF or SA)						
	Reforming #1						
	#2						
	C5/C6 Isomerization						
	Dimersol						
	Polymerization						
Hydrogen							
	Generation						
	Purification						
Other							
	Solvent Deasphalting						
	Sulfur Recovery						
	Tail Gas Recovery						
	Lube Oil						
	C4 Isomerization						
	Aromatics Production						
	Cogeneration						
	Other						

Company:

Refinery Location:

Table 3: Hydrogen Use and Feeds, by Hydrotreating Unit: Summer 1997

Measure	LSR Naphtha	Reformer Feed	Distillate		FCC Feed/ Hvy. GO	Resid	FCC Gasoline	BenSat	Other
			Desulf-urization	Dearo--matization					
Hydrogen (scf/bbl)									
Charge									
Consumption									
Sulfur Removal (%)									
Reduction in:									
Octane -- RON									
MON									
Aromatics (% pt.)									
Olefins (% pt.)									
Improvement in:									
Cetane number									
#1 Feed									
Boiling Range (°F)									
% of Charge									
Sulfur Content (ppm)									
Cetane number									
Aromatics (vol %)									
Olefins (vol %)									
Octane -- RON									
MON									
#2 Feed									
Boiling Range (°F)									
% of Charge									
Sulfur Content (ppm)									
Cetane number									
Aromatics (vol %)									
Olefins (vol %)									
Octane -- RON									
MON									
#3 Feed									
Boiling Range (°F)									

Company:

Refinery Location:

Table 3: Hydrogen Use and Feeds, by Hydrotreating Unit: Summer 1997

Measure	LSR Naphtha	Reformer Feed	Distillate		FCC Feed/ Hvy. GO	Resid	FCC Gasoline	BenSat	Other
			Desulf-urization	Dearo--matization					
% of Charge									
Sulfur Content (ppm)									
Cetane number									
Aromatics (vol %)									
Olefins (vol %)									
Octane -- RON									
MON									
#4 Feed									
Boiling Range (°F)									
% of Charge									
Sulfur Content (ppm)									
Cetane number									
Aromatics (vol %)									
Olefins (vol %)									
Octane -- RON									
MON									

Company:

Refinery Location:

Table 4: Gasoline Volume and Average Pool Properties, by Grade and Class: Summer 1997

Volume/ Property	California RFG			Arizona RFG			Conventional		
	Premium	Mid-Grade	Regular	Premium	Mid-Grade	Regular	Premium	Mid-Grade	Regular
Volume (bbl/d)									
Octane									
MON									
RON									
API Gravity									
RVP (psi)									
Oxygen (wt%)									
Aromatics (vol%)									
Benzene (vol%)									
Olefins (vol%)									
Sulfur (ppm)									
E200 (%)									
E300 (%)									
Butane content (vol%)									
Pentane content (vol%)									
Distillation (°F)									
IBP									
T10									
T30									
T50									
T70									
T90									
FBP									
Distribution of Oxygenates (vol%)*									
MTBE									
TAME									
Other									

Summer 1997 refers to the time period covering May 1 through August 31, 1997 (123 calendar days).

* Relative volume percent use of oxygenates -- sums to 100.

Company:

Refinery Location:

Table 5: Average Gasoline Blendstock Volume and Properties: Summer 1997

Blendstock	Volume* (bbl/d)	Octane MON	Octane RON	API Gravity	RVP (psi)	Aromatics (vol %)	Benzene (vol %)	Olefins (vol %)	Sulfur (ppm)	E200 (%)	E300 (%)	Distillation (°F) IBP	T10	T30	T50	T70	T90	FBP
Naphthas																		
Light Str. Run -- virgin																		
Light Str. Run -- desulf																		
Light coker -- virgin																		
Light coker -- desulf																		
Hydrocrackate																		
Light																		
Medium																		
Full range																		
Alkylate																		
Mixed																		
Propylene																		
Butylyene																		
Amylene																		
T90 controlled:																		
Mixed																		
Propylene																		
Butylyene																		
Amylene																		

Company:

Refinery Location:

Table 5: Average Gasoline Blendstock Volume and Properties: Summer 1997

Blendstock	Volume* (bbl/d)	Octane MON	Octane RON	API Gravity	RVP (psi)	Aromatics (vol %)	Benzene (vol %)	Olefins (vol %)	Sulfur (ppm)	E200 (%)	E300 (%)	Distillation (°F) IBP	T10	T30	T50	T70	T90	FBP
Reformate																		
Full range																		
Light																		
Heavy																		
Post-benzene satur.																		
Full range																		
Light																		
Post-T90 control																		
Full																		
Heavy																		
Other																		
Raffinate:																		
Full range																		
Light																		

Company:

Refinery Location:

Table 5: Average Gasoline Blendstock Volume and Properties: Summer 1997

Blendstock	Volume* (bbl/d)	Octane MON	Octane RON	API Gravity	RVP (psi)	Aromatics (vol %)	Benzene (vol %)	Olefins (vol %)	Sulfur (ppm)	E200 (%)	E300 (%)	Distillation (°F) IBP	T10	T30	T50	T70	T90	FBP
FCC Gasoline																		
Pre-desulfurization																		
Full																		
Light																		
Medium																		
Heavy																		
Post-desulfurization																		
Full																		
Medium																		
Heavy																		
Post-T90 control																		
Full																		
Heavy																		
Other																		

Company:

Refinery Location:

Table 5: Average Gasoline Blendstock Volume and Properties: Summer 1997

Blendstock	Volume* (bbl/d)	Octane MON	Octane RON	API Gravity	RVP (psi)	Aromatics (vol %)	Benzene (vol %)	Olefins (vol %)	Sulfur (ppm)	E200 (%)	E300 (%)	Distillation (°F) IBP	T10	T30	T50	T70	T90	FBP
Isomerate																		
Mixed																		
C5																		
C6																		
Dimate																		
Polymer Gasoline																		
N-Butane																		
Oxygenates																		
MTBE																		
TAME																		
Other Oxygenate																		
Other																		

Note: Stream properties should be reported with current level of butane control.

Summer 1997 refers to the time period covering May 1 through August 31, 1997 (123 calendar days).

* The entries in this column should sum to average daily gasoline production (all gasoline classes and grades).

Company:

Refinery Location:

Table 6: Jet, Distillate and Residual Fuel Oil Volume and Average Pool Properties: Summer 1997

Volume/ Property	Jet Fuel	Diesel Fuel			Residual Fuel Oil
		CARB Low Aromatic	EPA Low Sulfur	Other High Sulfur	
Volume (bbl/d)					
API Gravity					
Sulfur (ppm)					
Nitrogen (ppm)					
Freeze Point (°F)					
Smoke Point (mm)					
Naphthalenes (vol%)					
Aromatics (vol%)					
Polynuclear Aromatics (vol%)					
Cetane Number (clear)					
Cetane Improver (ppm)					
Cetane Number (additized)					
Pour Point (°F additized)					
Pour Point Depressant (ppm)					
Distillation (°F)*					
IBP					
T10					
T30					
T50					
T70					
T90					
FBP					

Summer 1997 refers to the time period covering May 1 through August 31, 1997 (123 calendar days).
* As available.

Company:

Refinery Location:

Table 7: Crude Oil Volume and Properties: Summer 1997

Name	Volume (bbl/sd)	API Gravity	Sulfur (wt%)	Nitrogen (wt%)	Crude Diluent (vol%)		
					Pentanes	Natural Gasoline	Other
Total Crude Slate							
Alaskan							
North Slope							
Cook Inlet							
California							
Elk Hills							
Kern River							
Outer Continental Shelf							
San Ardo							
San Joaquin Heavy							
San Joaquin Light							
Ventura							
Wilmington							
Imports							

Summer 1997 refers to the time period covering May 1 through August 31, 1997 (123 calendar days).

Company:

Refinery Location:

Table 8: Inputs From Outside the Refinery Gate (other than crude oil)
Summer 1997

Description	Average Volume (bbl/sd)	Supply Source of Inputs			Boiling Range (°F)	API Gravity	Sulfur (ppm)	Inventory Drawdown*
		Other Calif. Complex	Calif. Non-complex	Outside Calif.				
Natural Gas (foeb)								
MTBE								
Naphtha								
Alkylate								
Isomerate								
Hydrocrackate								
Reformate								
FCC Gasoline								
FCC Feed								
Vacuum Resid								
Other Unfinished Oils								
Other Inputs								

* Inventory drawdown refers to an inter-seasonal reduction in inventory.
Summer 1997 refers to the time period covering May 1 through August 31, 1997 (123 calendar days).

Company:

Refinery Location:

Table 9: Refinery Streams Sold or Stored (for non-summer use): Summer 1997

Description	Volume (bbl/sd)	Boiling Range (°F)	API Gravity	Sulfur (ppm)	Inventory Build*
Butanes					
Pentanes					
Naphtha					
Alkylate					
Isomerate					
Hydrocrackate					
Reformate					
FCC Gasoline					
FCC Feed					
Vacuum Resid					
Other					

Note: Excludes sales of refined products.
Summer 1997 refers to the time period covering May 1 through August 31, 1997 (123 calendar days).
* Inventory build refers to an inter-seasonal increase in inventory.

Company:

Refinery Location:

Table 10: CARB RFG Base Gasoline T50 Depression: Summer Season

Base Gasoline T50 Distillation Temperature (°F)	Percent Ethanol in Final Blend (vol %)									
	1	2	3	4	5	6	7	8	9	10
180										
185										
190										
195										
200										
205										
210										
215										
220										
225										
230										
235										
240										

Note: The purpose of this table is to obtain a sufficient number of data points to more accurately model the blending characteristics of ethanol with regard to the T50 suppresion effect on different types of CARBOB base gasolines.

Company:

Refinery Location:

Table 11: Additional Questions Regarding Refining Operations

1. What streams is your refinery fuel system now capable of handling (without regard to permitting issues)?

2. What feeds is your hydrogen plant now capable of handling?

3. What streams is your co-gen plant now capable of handling?

4. What class of gasoline (if any) would you expect to produce for Maricopa County, AZ starting in summer of 1999 (CARB RFG or Fed Phase 2 RFG)?

STAFF REPORT

SUPPLY AND COST OF ALTERNATIVES TO MTBE IN GASOLINE

TECHNICAL APPENDICES

Refinery Modeling Task 2:
Calibration of Refinery Model

OCTOBER 1998

CALIFORNIA
ENERGY
COMMISSION

Pete Wilson, ***Governor***

P300-98-013H

Evaluating the Cost and Supply of Alternatives to MTBE in California's Reformulated Gasoline

Project Report

REFINERY MODELING

Task 2: CALIBRATION OF THE REFINERY MODEL

Prepared for

California Energy Commission

by

MathPro Inc.

under

Subcontract No. CM6006W3

June 24, 1998

MathPro, Inc.

P.O. Box 34404
West Bethesda, Maryland 20827-0404
301-951-9006

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1.

1. INTRODUCTION

MathPro Inc. submits this report to the California Energy Commission pursuant to Task 2 (for the Refinery Modeling Subcontractor) of Subcontract CM6006W3 (Contract 500-96-012). Task 2 calls for calibration of the California statewide aggregated base case refinery model.

We developed a special variant of our refinery LP model (ARMS), whose outputs match key elements of the operations of the California refineries in the aggregate, as reported for Summer 1997. The calibration process involved:

- Developing a detailed description of the performance of the gasoline-producing refineries in California in Summer 1997, on the basis of refining principles and data from various sources (including the special survey conducted by CEC); and then

- Adjusting technical coefficients in the ARMS database (e.g., process yields, blendstock properties, etc.) and adding new elements to the ARMS model statement (e.g., processes, process operating modes, etc.) until the ARMS model yielded outputs (solutions) that closely match reported refining operations, with respect to crude slate, product volumes, product properties, and capacity utilization.

The modified and new elements will remain in the ARMS model throughout Task 3 – analysis of the various scenarios delineated in the Task 1 report.
2.

CALIBRATION CASE

2.1 Calibrating the Refinery Model

Calibration demonstrates the validity of the refinery LP model (ARMS) for the study at hand and establishes a base case for use in subsequent analysis. Calibration involves: (1) establishing an accurate representation of refining operations, in this case the aggregate operations of California gasoline-producing refineries; and (2) adjusting elements of the ARMS database, so that the ARMS model yields solution values that match with sufficient precision certain key measures of refinery operations.

We relied on information from publicly available documents, the CEC refinery survey, and interviews with refiners to characterize aggregate refinery operations for the 1997 Summer season in terms of:

- process capacities,
- crude oil slate,
- product slate,
- gasoline grade splits,
- prices for crude oil and refined products,
- product specifications and average properties for California RFG, Arizona RFG, and conventional gasoline; and
- product specifications and average properties for jet fuel and diesel fuel

The measures of refining operations we focused on when calibrating ARMS include:

- capacity utilization of various refining processes, particularly the major conversion units (coking, fluid cat cracking, and hydrocracking),
- product volumes,
- marginal refining costs at observed product volumes,
- marginal costs of product specifications,
- California RFG properties (as influenced by the Predictive Model), and
- jet fuel and diesel fuel properties.

2.2 Calibration Results

Our characterization of aggregate California refining operations, along with the calibration results are shown in Exhibits 1 through 12 (at the end of this report). In general, the key outputs of the ARMS aggregate model closely match the operations of the aggregate California refining sector.

The exhibits are as follows.

- **Exhibits 1.1** and **1.2** deal with process unit capacities and capacity utilization.

  Exhibit 1.1 shows (1) aggregate capacity, capacity utilization, and throughput, by process, as reported by the CEC survey, the API/NPRA survey (July 1997), the 1997 *Oil & Gas Journal* survey, and the 1997 DOE *Petroleum Supply Annual* and (2) the aggregate capacity profile that we established in ARMS for the calibration.

  Exhibit 1.2 shows (1) our estimates of the aggregate capacity profile, capacity utilization, and throughput, by process (**Reported/Derived**) and (2) the throughput and capacity utilization profiles generated by the ARMS model (**Calibration**). Of the fields labeled **Calibration**, **Capacity** denotes input to the ARMS model and **Thruput** and **Cap. Util.** denote outputs. The latter two fields show how the ARMS model uses the available aggregate capacity.

- **Exhibits 2.1**, **2.2**, and **2.3** deal with the crude oil slate.

  Exhibit 2.1 shows volumes and properties of domestic and imported crude oils run by the California refineries in Summer 1997, as reported by the CEC survey.

  Exhibit 2.2 shows volumes and properties of imported crude oils run by California refineries in 1997, as reported by DOE.

  Exhibit 2.3 characterizes the crude slate input to the ARMS model. In particular, it shows the volumes (K bbl/day), yields (of straight run fractions), assay distillations, and sulfur contents of the three constituents of the crude oil slate represented in ARMS: Alaskan North Slope (ANS), a domestic composite, and a foreign composite. The domestic and foreign composites have the volume-weighted average properties of, respectively, the California crudes and the imported crudes run by California refineries in Summer 1997.

- **Exhibit 3** deals with the full set of refinery *inputs* – crude oils, oxygenates, unfinished oils, fuel, and other inputs. The **Volume** and **Price** fields labeled **Calibration** denote outputs of the ARMS model – respectively, the computed volumes and marginal values (shadow prices) of refinery inputs.

- **Exhibit 4** deals with the full set of refinery *outputs* – including three gasoline classes (CARB RFG, Arizona RFG, and conventional), CARB diesel, EPA diesel, jet fuel, LPG, and other refined products. The **Volume** and **Price** fields labeled **Calibration** denote outputs of the ARMS model – respectively, the computed volumes and marginal values (shadow prices) of refinery outputs.

- **Exhibits 5.1**, **5.2**, and **5.3** deal with gasoline properties, by class and grade.

  Exhibit 5.1 shows the properties, by class and grade, of gasolines produced in Summer 1997, as reported by the CEC survey. The reported properties include octane, the

Predictive Model properties, API gravity, butane and pentane content, ASTM distillation, and oxygenate content.

Exhibit 5.2 shows similar information on gasolines produced in Summer 1996, as reported by the API/NPRA survey.

Exhibit 5.3 compares the surveyed gasoline properties presented in the two preceding exhibits with the corresponding computed properties. For each gasoline class, the field labeled **Calibration** denotes outputs of the ARMS model – computed average properties of the indicated gasoline class.

Exhibit 5.3 also shows the emissions performance of each gasoline class – based on both surveyed average properties and computed average properties from the ARMS model. We computed these values using the CARB Predictive Model.

- **Exhibits 6.1**, **6.2**, **6.3**, and **6.4** deal with the ASTM distillation curves for the various gasoline classes and for the entire gasoline pool. Each exhibit shows – for a particular gasoline class – distillation curve(s) drawn from survey data (CEC and API/NPRA) and the distillation curve output by the ARMS model.

  Distillation curves output by the ARMS model reflect the distillation curves of individual gasoline blendstocks (e.g., FCC gasoline, reformate, alkylate) registered in the ARMS database. The distillation curves in the ARMS database were among the technical coefficients modified in the calibration effort.

- **Exhibit 7** deals with gasoline composition, by class. All of the values shown in this exhibit are outputs of the ARMS model.

- **Exhibit 8** deals with distillate product properties. The exhibit shows properties of jet fuel, CARB diesel fuel, and EPA diesel fuel produced in California. The reported properties include API gravity, aromatics content, sulfur content, cetane number (clear), and ASTM distillation. The exhibit compares surveyed distillate product properties with the corresponding computed properties. For each distillate product, the field labeled **Calibration** denotes outputs of the ARMS model – computed average properties of the indicated distillate product.

- **Exhibit 9.1** shows the distillation curves for two classes of FCC gasolines – low sulfur and high sulfur – as reported in the CEC survey and as represented in ARMS. **Exhibit 9.2** shows how the high sulfur FCC gasoline is fractionated in ARMS and the effect of subsequent desulfurization and olefins saturation on the distillation curves of those streams.

- **Exhibits 10.1 and 10.2** show: (1) combinations of T_{50}/E_{200} and T_{90}/E_{300} reported in the CEC and API/NPRA surveys; (2) revised combinations of T_{90}/E_{300} such that the E_{300}s are more consistent with reported distillation curves; (3) linear relationships for

T_{50}/E_{200} and T_{90}/E_{300} developed by EPA; and (4) linear relationships for T_{50}/E_{200} and T_{90}/E_{300} developed by MathPro and used in this study.

- **Exhibit 11** shows (a subset of) gasoline blendstocks in ARMS, properties and octanes for such blendstocks, and the composition of the three types of gasoline in the Calibration Case.

- **Exhibit 12** provides a summary of modifications and enhancements made to ARMS for this study.

3.0 METHODOLOGY

This section discusses the approach, assumptions, and modifications and enhancements to ARMS for calibrating ARMS to represent the aggregate operations of the California refining sector.

3.1 Unit Operating Rates

We calibrated ARMS to match the operating rates (thoughput) of conversion units – coking, fluid cat cracking, and hydrocracking – through the following iterative procedure.

- Fixed aggregate crude oil purchases at the reported throughput for atmospheric distillation.
- Increased purchases of residual oil until coker throughput matched reported throughput.
- Added purchases of heavy gas oil until total purchases of unfinished oils were similar to reported purchases and the combination of FCC and gas oil hydrocracking was consistent with information from the CEC survey.
- Required the solvent deasphalting unit to operate at full capacity and designated part of its output as FCC feed.
- Modified the capacity for gas oil hydrocracking until FCC throughput matched reported throughput.
- Initially capped distillate hydrocracking capacity such that the combined capacity of gas oil and distillate hydrocracking matched reported hydrocracking throughput; subsequently set distillate hydrocracking capacity equal to reported hydrocracking capacity less gas oil hydrocracking capacity established in ARMS.

In the final calibration case: (1) all resid boiling range (1050°+) material is processed by the cokers (primarily) and the solvent deasphalter; (2) all FCC clarified oil is processed by the cokers; (3) all gas oil boiling range (620° – 1050°) material is processed by the FCC unit (primarily) or the gas oil hydrocracker; (4) no distillate (500° – 620°) or resid (1050°+) material is processed by the FCC unit; (5) most light cycle oil, all coker distillate, some virgin distillate, and all heavy FCC gasoline fractionated out for T_{90} control is processed by the distillate hydrocracker; and (6) the gas oil hydrocracker would run additional material if allowed.

We adjusted the operating rates of other units as follows.

- TAME. Set a minimum on depentanization of FCC gasoline to provide feed for

and insure operation of TAME units. (The minimum is based on the combined FCC capacity of the two refineries with TAME units.)

- Cat poly plant. Designated polymer gasoline as an aviation gasoline blendstock (and eliminated other streams as blendstocks) to insure operation of the small cat poly plant.

- Reforming. Represented all reforming capacity as medium pressure, i.e., 150 - 350 psi.

- Alkylation. Required investments in light ends processing to support any use of FCC olefin-maximizing catalysts. (Olefin-maximizing catalysts increase the availability of feeds for alkylation.) None was used in the Calibration Case.

- FCC feed hydrotreating. Required all FCC feed to be hydrotreated.

- FCC gasoline hydrotreater. Adjusted the extent of FCC gasoline hydrotreating by modifying: (1) the sulfur content of FCC gasolines; (2) the desulfurization and olefin saturation rates for the FCC gasoline hydrotreater (percent reductions in sulfur and olefins); and (3) the ratio of light feed to total FCC gasoline feed hydrotreated.

3.2 Crude Oil Slate

In characterizing the California crude oil slate, we used crude assays (for California crudes and ANS) supplied by Purvin & Gertz and crude assays (for foreign crudes) from public sources.

We used these assays to establish the ARMS representations of crude distillation yields and the relevant properties of crude oil fractions produced in the crude running unit. In this procedure, we characterize each crude as a set of crude oil fractions, which we select from a pre-defined set of crude oil fractions (each with a specific boiling range, API gravity, and sulfur content) in our database. For example, ARMS has five heavy gas oil fractions (800° - 1050°) and six vacuum resid fractions (1050° +), each defined by sulfur content and API gravity.

We used the crude oil volumes, sulfur contents, and API gravities reported in the CEC survey to develop the relative volumes of crude oils comprising the domestic (California) composite crude. Tha is, the domestic composite crude is a weighted average of ARMS representations of six California crudes – San Joaquin Heavy, San Joaquin Light, Line 63, Elk Hills, Wilmington, and OCS. Likewise, the foreign composite is a weighted average of foreign crudes represented in ARMS, with weights based on detailed data on crude oil imports reported by DOE (Exhibit 2.2).

The numbers at the bottom of Exhibit 2.3 represent the weighted average API gravity and

sulfur content, drawn from the crude oil assays, weighted by the crude oils' volume fractions in the composite crudes. The corresponding numbers above the bottom set represent the API gravity and sulfur content of the composite crudes as represented in the ARMS model. These values are the volume-weighted averages of the API gravities and sulfur contents of the pre-defined crude fractions that we used to represent the crude oils.

The California crudes tend to have combinations of API gravity and sulfur content that do not match up as well with our pre-defined set of crude oil fractions as other crudes do. In particular, the California crudes tend to be unusually heavy given their sulfur content. Hence, when we select crude fractions that match on sulfur content, we end up with a set of fractions that is lighter than the actual California crudes. Further, the OCS crude has a higher sulfur content in the atmospheric resid boiling range (620° +) than any of our corresponding crude oil fractions. The end result is that our domestic composite crude matches the weighted average of California crudes in terms of the distillation curve, but is lighter and has somewhat lower sulfur content. This discrepancy has only minor effects on the Calibration Case and will have no material effect on the Task 3 analysis

3.3 Product Slate

We set limits for various refined products as follows:

Refined Product	Type of Limit
Propane	Upper bound
Propylene	Fixed
Butane	Lower bound
Mixed Butylenes	Upper bound
Aviation Gas	Fixed
Naphtha	Fixed
Gasoline	Fixed
Jet Fuel	Fixed
CARB Diesel	Fixed
EPA Diesel	Narrow range
Other Distillate	Fixed
Unfinished Oils	Open
Residual Oil	Open
Lubes & Waxes	Fixed
Sulfur	Open
Coke	Open

With conversion unit throughputs similar to those reported in surveys, ARMS initially produced more distillate products and less residual products and coke than reported. To bring the ARMS product slate more closely with the reported product slate we:

- Modified yields for delayed cokers to produce more coke and less coker gas.[1]

- Established an unfinished oil category as an outlet for light cycle oil used as cutter stock for residual oil blending and priced it such that (1) there is a small incentive to produce light cycle oil for this purpose and (2) all available resid boiling range material is processed by the cokers.

- Established a recipe blend (tar and kerosene) for a producing resid from heavy material produced by the solvent deasphalter.

- Added a new product category for "other distillate" – a low volume, high sulfur content, heavy distillate product.

The net result is that ARMS "produces" the reported volumes of the high-value refined products -- gasoline, jet fuel, and diesel fuel -- but less residual oil.

3.4 Shadow Values for Inputs and Refined Products

Shadow values for refinery inputs (e.g., crude oil and unfinished oils) indicate the marginal value in ARMS of an additional unit of input. Likewise, shadow values for refined products indicate the marginal cost in ARMS of increasing production by one unit.[2]

We did not set up the Calibration Case so that shadow values would match reported market prices for inputs and refined products. Instead, we constrained most inputs and refined product outputs to equal reported volumes.[3] In general, when refined product volumes are constrained to be equal to reported volumes, shadow values should be:

1. Higher for higher quality inputs (e.g., lighter, lower sulfur crudes should have higher shadow values than heavier, higher sulfur crudes and purchased blendstocks such as alkylate should have higher shadow values than gas oils).

2. Higher for refined products with tighter standards (e.g. CARB RFG should have a higher shadow value than Arizona RFG which, in turn, should have a higher shadow value than conventional gasoline).

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[1] We initially included three types of cokers in the ARMS representation – delayed, fluid, and flexi. Because of discrepancies between surveys in designating coking capacity as fluid versus flexi, we treated all such capacity as fluid. This caused coke production to increase (above reported volumes) because flexi cokers produce substantially less coke than fluid cokers.

[2] The marginal costs in ARMS for refined products do *not* include capital charges associated with investments already made for existing process capacity.

[3] If no constraints are imposed on specific inputs or products, i.e., required volumes are "open," shadow values will equal the prices for those inputs and products (given that there is some volume of input or production).

3. Fairly close to reported market prices (averaged over time periods long enough to remove fluctuations caused by market disruptions).

As shown in Exhibits 3 and 4, shadow values for inputs and refined products in ARMS are consistent with these requirements.

3.5 Ratio Constraints

We used ratio constraints in the Calibration Case in two general ways:

- Minimize the extent of *cherry-picking.*

  Cherry-picking occurs when a refinery LP model selectively processes certain streams that in actual refineries are commingled with others and, in practice, cannot be processed separately. For example, ARMS includes a number of distinct distillate boiling range streams, each with a different sulfur content. Left to its own devices, ARMS (as would most refinery LP models) would select the high sulfur content streams to desulfurize and would not desulfurize low sulfur content streams. This leads to over-optimization, because actual refineries cannot segregate streams by sulfur content – they have to process a commingled stream.[4]

- Constrain the operations of specific process units in ARMS to be consistent with operations of those units in the California refining sector.

More specifically, we set ratio constraints such that:

1. Light gas oil streams (defined by API gravity and sulfur content) were processed in the gas oil hydrocracker in proportion to their relative volumes in the crude oil slate (with an adjustment for production of coker gas oil).

2. Light and heavy gas oils (defined by API gravity and sulfur content) were processed in the conventional FCC feed hydrotreater in proportion to their relative volumes in the crude oil slate (adjusted for gas oil produced by cokers and processed by the gas oil hydrocracker). The “deep” FCC feed hydrotreater processed all remaining gas oils.

3. Resid streams (defined by API gravity and sulfur content) were processed in the delayed and fluid cokers in proportion to their relative volumes in the crude oil slate. We did not impose constraints on coking of FCC-produced clarified oils.

4. Virgin distillate streams (defined by API gravity, sulfur content, and other properties) were processed in the distillate hydrocracker in proportion to their relative volumes in the

[4] Over-optimization denotes the tendency of refinery LP modeling to indicate higher aggregate profit contributions or lower incremental costs for a given refining operation than could occur in practice for a given set of refinery capital stock, product specifications, and market conditions.

crude oil slate.

5. Virgin heavy naphtha, kerosene, and distillate streams (defined by API gravity, sulfur content, and other properties) were processed in the distillate hydrotreater in proportion to their relative volumes in the crude oil slate. We did not impose ratio constraints on desulfurization of FCC-produced light cycle oil, nor on any dearomatized streams.

6. Light cycle oil can comprise only a small fraction of the distillate product pool. (The constraint is imposed by limiting desulfurization of light cycle oil to less than 2.3% of distillate hydrotreating throughput and preventing dearomatization of light cycle oil.) The net result of this and other modifications to ARMS is that no light cycle oil is blended to the distillate product pool in the Calibration Case.

7. The throughputs for the conventional and deep FCC feed hydrotreating units were in proportion to our estimate of the capacities of those units in the California refining sector.

8. FCC conversion rates were similar for low and high sulfur feeds.

9. At least 15% of the FCC gasoline treated to reduce olefins and sulfur was light FCC gasoline (to reflect that some refiners treat full-range FCC gasoline).

10. Fractionation of FCC gasoline and hydrocracking of the heavy ends (for T_{90} control) was in proportion to the relative volumes of FCC gasoline produced from conventional and deep hydrotreated FCC feeds.

3.6 FCC Gasoline Sulfur Control

ARMS, as configured for this study, controls the sulfur content of FCC gasoline through two routes – (1) deep hydrotreating of FCC feed and (2) conventional hydtrotreating of FCC feed in combination with FCC gasoline hydrotreating and olefins saturation.

Deep hydrotreating of FCC feed

About 53% of FCC feed hydrotreating capacity in California is capable of reducing the sulfur content of gas oils by over 95%. Data from the CEC survey and information provided by refiners indicates that FCC gasoline produced from FCC feeds desulfurized by such units has very low sulfur content, relatively high aromatics content, and low olefins content. We set these properties for FCC gasoline (at 70% conversion) as follows: sulfur – 60 ppm, aromatics – 33.1 vol%, and olefins – 11.6 vol%.

The only disposition in ARMS of FCC gasoline produced from deep hydrotreated feeds is gasoline blending, i.e, no further olefin control or desulfurization is allowed. However, we allow the heavy end (a 375°+ material – 11% by volume) of this FCC gasoline to be

fractionated out and hydrocracked for T_{90} control.

Conventional hydtrotreating of FCC feed in combination with FCC gasoline hydrotreating and olefins saturation

About 47% of FCC feed hydrotreating capacity in California is capable of reducing the sulfur content of gas oils by about 85%. FCC gasoline produced from feeds subject to conventional desulfurization has a low sulfur content (by national standards), relatively low aromatics content, and high olefins content. We set these properties for FCC gasoline (at 70% conversion) as follows: sulfur – 400 ppm, aromatics – 27.0 vol%, and olefins – 32.6 vol%.

In ARMS, FCC gasoline produced from conventional hydrotreated FCC feed may be (1) blended directly to gasoline, (2) depentanized and then blended to gasoline, (3) split into light, medium, and heavy fractions for further desulfurization (and olefins control) and subsequent blending to gasoline; and (4) fractionated and the heavy end (a 375°+ material – 10% by volume) hydrocracked for T_{90} control.

We assumed that FCC gasoline desulfurization and olefin saturation (1) incur no yield loss and (2) reduce the sulfur and olefins content of FCC gasoline by the following percentages.

FCC Gasoline Fraction	Reduction in Sulfur	Reduction in Olefins
Light (22%)	75%	75%
Medium (50%)	90%	90%
Heavy (28%)	90%	90%

We also assumed that the octanes ((R+M)/2) of the FCC gasoline fractions are reduced as follows: light – 9 numbers; medium – 4 numbers; heavy – 1 number.

The distillation curves incorporated in ARMS for the two types of FCC gasolines (low sulfur and high sulfur) are shown in Exhibit 9.1. The distillation curves for the various FCC gasoline fractions and desulfurized fractions are shown in Exhibit 9.2.

3.7 T_{90} Control

ARMS has four options for controlling the T_{90} of gasoline.

- Fractionate FCC gasoline and hydrocrack the heavy end. This procedure was described in the preceding section. ARMS separated and hydrocracked about 22 K bbl/d of the heavy end of FCC gasoline. Thus, about 60% of produced FCC gasoline was fractionated for T_{90} control.

- Fractionate alkylate and distillate blend or hydrocrack the heavy end (10% of C4 alkylate, by volume).

- Fractionate heavy reformate and hydrocrack the heavy end (50% of heavy reformate, by volume).

- Fractionate 250°–325° naphtha to 250°–300° and 300°–325° fractions, followed by reform of the lighter fraction, and distillate blend the heavier fraction.

ARMS used only the first option to control T_{90} when capital charges for fractionation were included in the cost of T_{90} control. Consequently, we allowed ARMS to practice T_{90} control through FCC fractionation (with no capital charge). The other options remain available, but require building fractionation capacity. (With no capital charge assigned, fractionation of FCC gasoline and fractionation 250°-325° naphthas would have been used about equally for T_{90} control.)

3.8 Benzene Control

ARMS, as configured for this study, has two options for benzene control.

- Fractionate 160°-250° straight run naphtha to segregate benzene and benzene precursors in a 160°-175° cut, followed by either gasoline blending or isomerization of the 160°-175° cut and reforming of the 175°-250° cut (producing a light, low benzene content reformate). ARMS fractionates all light straight run naphtha and isomerizes the entire volume of 160°-175° straight run naphtha[5].

- Benzene saturation of reformate produced from 160°-250°, 250°-300°, and 250°-325° virgin naphthas, light coker naphtha, and medium and heavy hydrocrackate. ARMS sends most reformate, excluding reformate produced from the 175°-250° cut discussed above, to benzene saturation.

Thus, ARMS reduces the benzene content of reformate to nearly the full extent allowed by the naphtha fractionation and benzene saturation options, i.e., about 90% of all produced reformate is benzene-controlled. (We did not allow benzene extraction or benzene alkylation as benzene control options because California refineries do not practice those process options.)

3.9 Controlling Gasoline Properties

[5] ARMS does not have process options for fractionating light coker naphtha (after desulfurization) and medium hydrocrackate reformer feeds. This results in production of high benzene content, light reformates, most of which are treated in the benzene saturation unit, along with reformates produced from 250° + naphtha and heavy hydrocrackate feeds.

The calibration case includes three types of gasolines: CARB RFG, Arizona RFG, and conventional gasoline. We controlled the properties of Arizona RFG and conventional gasoline directly, i.e., we set pool properties for those gasolines equal to the pool properties reported in the CEC survey.[6] We did not control directly properties for CARB RFG. Rather, they were determined in ARMS by the interaction of (1) the techno-economics of gasoline production and (2) California's Predictive Model.[7]

ARMS incorporates a "reduced form" of California's Predictive Model. A reduced-form model attempts to capture in a simple mathematical structure the major relationships of a large or more complicated model. To be useful, a reduced form of the Predictive Model must: (1) calculate changes in emissions close to those calculated by the Predictive Model; (2) approximate the functional relationships between changes in emissions and specific gasoline properties, so that ARMS can identify the lowest cost CARB blend consistent with quality and emission performance constraints; and (3) be in a form that can be integrated into a refinery LP model. This last requirement can be satisfied if the reduced-form is "separable." A non-linear equation is separable if it has no terms that are a function of more than one variable. All linear equations are separable.

Two non-linear reduced-form versions of the Predictive Model are incorporated in ARMS. In the first version, the oxygen content of CARB RFG must be within a range 1.8 to 2.2 wt%. In the second version, the oxygen content of CARB RFG may vary between 0 and 1.8 wt%. In the Calibration Case, we used the version in which the pool oxygen content of CARB RFG must be within a range of 1.8 to 2.2 wt%. (We will estimate a third version of the Predictive Model for use in assessing ethanol blending in excess of 2.2 wt% oxygen.)

Developing the Reduced-Form Predictive Model

We developed the non-linear reduced-form models as follows:

1. We specified ranges for each Predictive Model property within which CARG RFG properties are likely to lie.

2. We generated 2000 sets of random "blends" (combinations of randomly generated sets of gasoline properties within the specified ranges) for each of the two versions of the Predictive Model and computed the corresponding emissions changes for VOCs, NOx, and toxics via the Predictive Model.

3. We used standard regression analysis to estimate separable, non-linear equations for

[6] The one exception is benzene content, which we limited to 0.80% because ARMS had difficulty in initial calibration runs in meeting the lower benzene levels of 0.64% and 0.73% reported for Arizona RFG and conventional gasoline, respectively. In subsequent calibration runs, ARMS could reduce benzene to lower levels, as evidenced by the presence of some uncontrolled reformate in the gasoline pool.

[7] The one exception is oxygen content, for which we set a minimum of 2.1 wt% to agree with reported values and the federal "averaging" minimum.

VOCs, NOx, and toxics.

The degree of fit and standard error of estimate for the reduced-form equations comprising the "fixed oxygen" (oxygen between 1.8 and 2.2%) and "variable oxygen" (oxygen content between 0 and 1.8%) versions of the Predictive Model are as follows.

	Fixed Oxygen		Variable Oxygen	
Emission	R^2	Std. Error	R^2	Std. Error
VOCs	.9985	.0968	.9990	.0576
NOx	.9983	.0233	.9980	.0273
Toxics	.9990	.1103	.9990	.1061

The Predictive Model is specified in terms of the T_{50} and T_{90} of gasoline (the temperature in °F at which 50% and 90% of gasoline is distilled off, respectively). In refinery LP models, however, gasoline blendstocks and blended gasolines generally are specified in terms of the percent off at various temperatures. For example, the E_{200} and E_{300} of a gasoline refer to the volume percents distilled off at 200°F and 300°F, respectively. Therefore, integration of the Predictive Model into a refinery LP model requires a translation between the two ways of specifying the distillation properties of gasoline.

EPA developed the following two equations for translating T_{50} to E_{200} and T_{90} to E_{300}:

$$E_{200} = 147.91 - 0.49 * T_{50}$$
$$E_{300} = 155.47 - 0.22 * T_{90}$$

EPA's equations are shown in Exhibits 10.1 and 10.2, along with reported combinations of T_{50}/E_{200} and T_{90}/E_{300} from the CEC Survey and the API/NPRA Survey. Because the EPA equations (1) do not pass through the points of equality between E values and T values, i.e. (200°F,50%) and (300°F,90%), and (2) are inconsistent with reported values from the two surveys (particularly for T_{90} and E_{300}), we estimated alternative equations for translating between E and T values.

The CEC and API/NPRA surveys report values for E_{300} that are slightly lower than indicated by the distillation curves defined by T_{10} through T_{90} values. We revised the E_{300} values slightly (increased them so they were consistent with the distillation curves) and estimated equations for translating between E and T values.

Our equations are shown below and also are graphed in Exhibits 10.1 and 10.2. (An initial equation for E_{300} also is shown in Exhibit 10.2.) These equations are implicitly incorporated in the reduced-forms of the Predictive Model integrated in ARMS.

$$E_{200} = 125.38 - 0.38 * T_{50}$$
$$E_{300} = 196.15 - 0.35 * T_{90}.$$

Integrating the Predictive Model in ARMS

Embedding the reduced-form models in ARMS involved three steps.

1. We developed a piecewise-linear approximation for each equation in the reduced-form model. (One can approximate the reduced-form to any desired accuracy by using shorter intervals and more line segments.)

2. For each piecewise-linear approximation, we created a set of new LP model variables, called Type 2 Special Ordered Sets, containing one variable for each break point, and an LP model equation summing the levels of all the variables in the set and setting the sum equal to 1.

3. For each gasoline pool property (e.g. aromatics content), we created an LP model equation connecting the gasoline blending sector of the model to the new reduced form sector and established a set of constraints imposing percentage emission reductions for each emission type.

This makes the linearized reduced form an integral part of the gasoline blending sector of the refinery LP model. The expanded ARMS model can be processed (generated, solved, and reported) in the conventional way. It treats the constraints imposed by the Predictive Model just as it does other techno-economic constraints.

Shadow Values for Gasoline Property Constraints

All constraints on gasoline properties set in the Calibration Case (either directly or through the Predictive Model) are tight, i.e., there is a cost associated with meeting each constraint for each type of gasoline – CARB RFG, Arizona RFG, and conventional gasoline. Shadow values for each property constraint are higher for CARB RFG and Arizona RFG than for conventional gasoline. Further, none of the shadow values is exceedingly large, indicating that ARMS is not improperly constrained by specific property constraints.

3.10 Gasoline Blendstock Properties

Exhibit 11 shows the ARMS blendstocks comprising each gasoline pool (CARB RFG, Arizona RFG, and conventional), along with the properties and octane of the blendstocks. We set the properties of the FCC gasolines to be consistent with the CEC survey results and to generate properties of California RFG in the Calibration Case that matched those reported in surveys. We reduced the sulfur content of most blendstocks to agree with sulfur levels reported in the CEC Survey. We modified the octane of hydrocrackates and the aromatics content of FCC gasoline and reformates to be consistent with the CEC survey. Finally, we modified the distillation curves of most blendstocks – C_{4s}, naphthas, hydrocrackates,

alkylates, FCC gasoline, and reformates – such that the distillation curve for the entire gasoline pool "produced" by ARMS (a weighted average of CARB RFG, Arizona RFG, and conventional gasoline) closely tracked the pool distillation curve calculated using survey data.

3.11 Summary of Modifications to ARMS

Exhibit 12 provides a list of the modifications and enhancements made to ARMS in developing the Calibration Case and the purpose of each.

3.12 Summary of Revisions to Initial Calibration Case

CEC, WSPA, and other interested parties reviewed the draft Task 2 report detailing the results of our initial Calibration Case. In response to comments on the initial Calibration Case and our own internal review, we made the following revisions to the Calibration Case.

- Modified yields for the delayed coker (removed production of coker bottoms) and hydrocrackers (removed production of resid blending material).

- Modified the capacity for gas oil hydrocracking (so that FCC throughput agreed with reported volumes) and removed the capacity constraint on distillate hydrocracking set in the initial calibration work. (Distillate hydrocracking capacity is now equal to total reported hydrocracking capacity, minus capacity for light gas oil hydrocracking.)

- Modified ratio constraints controlling the FCC gasoline desulfurization unit such that 15% of FCC gasoline undergoing sulfur and olefins control must be light FCC gasoline. (Previously the constraint was set at 22%. The lower percentage reflects that some, but not all, refiners treat full-range FCC gasoline.)

- Established ratio constraints for the FCC unit so that conversion rates for low and high sulfur FCC feeds are similar. (We imposed ratio constraints because modifications made regarding the disposition of light cycle oil led to cherry-picking in the FCC unit, i.e., the conversion rate for high sulfur feed became substantially lower than the conversion rate for low sulfur feed.)

- Limited the extent to which light cycle oil is blended in distillate products (by imposing ratio constraints in the distillate desulfurization unit and preventing dearomatization of light cycle oils).

- Established a new distillate product to represent production of a small volume (15 K bbl/d) of heavy, high sulfur distillate material (and correspondingly reduced production of EPA diesel).

- Set up an unfinished oil product category for light cycle oil used as residual oil cutter stock.

- Set an upper limit of 4 K bbl/d for sales of mixed butylenes (consistent with DOE reported sales volumes).

- Represented all reforming as medium pressure (150 – 350 psi) rather than low pressure (< 150 psi).

- Reduced the octane of hydrocrackate to be more consistent with the CEC survey. (This increased reformer throughput and severity and caused a small volume of medium hydrocrackate, in addition to all heavy hydrocrackate, to be used as reformer feed.)

- Created a new blendstock to represent isomerate produced from 160-175° naphtha. (Previously, such production was represented by isomerate produced from C5-160° naphtha.)

- Revised the sulfur contents of oxygenates as follows: captive MTBE – 50 ppm; merchant MTBE – 10 ppm; and captive TAME – 50 ppm.

- Modified the distillation curves for medium, high-sulfur FCC gasoline. (They were incorrectly entered in ARMS in the previous Calibration Case.)

- Reduced the aromatics content of FCC gasoline to account for higher conversion in the new Calibration Case.

- Reduced the aromatics content of reformates to be more consistent with the CEC survey and more closely match gasoline pool properties.

- Modified the ARMS representation of the Predictive Model for the revised relationship between E300 and T90.

This series of modifications improved our representation in ARMS of the aggregate operations of the California refining sector.

STAFF REPORT

SUPPLY AND COST OF ALTERNATIVES TO MTBE IN GASOLINE

TECHNICAL APPENDICES

Refinery Modeling Task 3:
Supply Scenario Modeling Runs

OCTOBER 1998

CALIFORNIA
ENERGY
COMMISSION

Pete Wilson, ***Governor***

P300-98-013I

Evaluating the Cost and Supply of Alternatives to MTBE in California's Reformulated Gasoline

Interim Report

REFINERY MODELING

Task 3: SUPPLY SCENARIO MODELING RUNS

SELECTED OXYGENATE SUPPLY SCENARIOS

Prepared for

California Energy Commission

by

MathPro Inc.

under

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MathPro, Inc.

P.O. Box 34404
West Bethesda, Maryland 20827-0404
301-951-9006

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EXHIBITS 1 – 10

1.

1. INTRODUCTION

MathPro Inc. submits this interim report to the California Energy Commission pursuant to Task 3 (for the Refinery Modeling Subcontractor) of Subcontract CM6006W3 (Contract 500-96-012). Task 3 calls for developing intermediate- and long-term Reference Cases and conducting a series of modeling runs of alternative oxygenate Supply Scenarios delineated in the Task 1 report.

CEC has specified over 60 Supply Scenarios for analysis. In this interim report, we examine a first set of those scenarios, for both the intermediate term and long term, consisting of the:

- Reference cases;
- MTBE cases in which H.R. 630 is assumed passed;
- No Oxygenate cases in which H.R. 630 is assumed passed; and
- A series of cases in which ethanol, TBA, ETBE, and mixed oxygenates are assumed to be the replacement oxygenates.

We used the calibrated California statewide aggregated refinery model (described in the Task 2 report) as the basis for developing the intermediate- and long-term Reference Cases. We then modified key elements of the Reference Case refinery model representations to assess the implications of an MTBE ban under alternative oxygenate Supply Scenarios. This involved:

- Adjusting the calibrated California refinery model for: (1) projected growth in refined product demand; (2) growth in refining process capacity necessary to supply future refined product demand; and (3) Phase 2 RFG standards on gasoline supplied to Arizona; and

- Incorporating in ARMS: (1) supply curves for imported oxygenates (ethanol, ETBE, TBA, and TAME), as estimated by ESAI; (2) supply curves for imported CARBOB (for blending with alternative oxygenates) and alkylate, as estimated by Purvin & Gertz; (3) supply curves for imported isomerate, diesel fuel, diesel fuel blendstocks, and jet fuel, as estimated by MathPro; (4) a reduced-form of the Predictive Model for oxygenate levels ranging from 2.2 to 2.7 wt%; and (5) a flat limit operating mode for the Predictive Model.

These new elements enabled us to represent in ARMS the sets of assumptions defining each of the Supply Scenarios and to assess the effects of an MTBE ban under each of the Supply Scenarios.

The remainder of this report describes the Reference Cases and the results of the refinery modeling for the Supply Scenarios.

2. REFERENCE CASES

2.1 Establishing the Reference Cases

Task 3 calls for assessing the effects of an MTBE ban in an intermediate-term and a long-term time period. Intermediate-term denotes a period during which oxygenate markets adjust to an MTBE-ban-induced change in oxygenate demand, but during which no additional oxygenate production capacity and refining process capacity (other than from debottlenecking) can be brought on-line. Long-term denotes a period during which oxygenate markets, oxygenate production capacity, and refining process capacity fully adjust to an MTBE ban. In developing the Reference Cases, we use the year 2002 to represent the intermediate term and the year 2005 to represent the long term.

To develop the Reference Cases, we modified the Calibration Case to account for: (1) growth in refined product demand; (2) increases in refinery capacity necessary for the California refining sector to satisfy projected product demands without importation of finished products; and (3) federal Phase 2 RFG standards for Arizona gasoline. We also consolidated the crude oil slate into a single composite crude oil with crude oil fractions equal to the weighted average of crude oil fractions in each of the crude oils in the Calibration Case.[1]

The projections of refined product demands and refining process capacity are developed in **Exhibits 1 – 3.**

Exhibit 1 shows projected growth rates in California's demand for selected refined products. According to these projections (developed by CEC), demand for gasoline, jet fuel, and CARB diesel fuel will be about 7 to 10% and 13 to 17% higher in 2002 and 2005, respectively, than in Summer 1997 (the calibration period).

Exhibit 2 shows projected refined product demands for 2002 and 2005. We calculated demands for California RFG, jet fuel, and CARB diesel for 2002 and 2005 by multiplying refinery output from the 1997 Calibration Case by the corresponding growth factors shown in Exhibit 1. Projected refinery output of Arizona gasoline and conventional gasoline is calculated using projected growth rates in demand for gasoline in Maricopa County, Arizona. Projected refinery output of conventional gasoline is calculated using the same projected growth rates as for California RFG. Demands for EPA diesel and other distillate fuel oil are calculated using the same projected growth rates as for CARB diesel. Demands for other refined products are calculated using the same growth rate as for jet fuel (1.5% per year).

Exhibit 3 shows aggregate refinery process capacities in the Calibration Case and in the 2002 and 2005 Reference Cases. We assumed sufficient "capacity creep" (from debottlenecking,

[1] We used a single composite crude because: (1) we expected the volume of crude oil purchases to vary across Supply Scenarios; (2) many of the ratio constraints developed for the Calibration case are specified in terms of ratios of certain crude oil fractions; and (3) using a single composite crude ensures that the ratios of purchased crude oil fractions in the Calibration Case are maintained across all Reference and Supply Scenario case, so that ratio constraints need not be re-set on a case-by-case basis.

revamping, and expansion of units) so that the aggregate California refining sector could supply the projected product demands (i.e., no imports of finished products). We used the following procedures to adjust refining capacity in the Reference Cases.

2002 Reference Case. Increased capacity by 5% (1% per year) from the Calibration Case for crude distillation, coking, fluid cat cracking, distillate and gas oil hydrocracking, alkylation, pen-hex isomerization, distillate desulfurization, benzene saturation, hydrogen, and lube oil. Allowed ARMS to add capacity (with no capital charge) for debutanization, light naphtha splitting, naphtha and reformer feed desulfurization, distillate dearomatization, and FCC naphtha splitting; and then set limits on capacity 5% higher (except for naphtha and reformer feed desulfurization and distillate dearomatization, which are left unconstrained). Held capacity constant dimersol, polymerization, reforming, MTBE, TAME, FCC naphtha desulfurization, butane isomerization, and solvent deasphalting.

This procedure results in most process units -- except fluid coking and gas oil hydrocracking (which are tight in the Calibration Case) and some minor processes (such as dimersol, MTBE, TAME, butane isomerization, and solvent deasphalting) -- having some degree of slack capacity in the Reference Case. The slack ranges from about 2 to 5%, but is larger for some process units, such as pen/hex isomerization, reforming, and distillate desulfurization.

2005 Reference Case. Allowed ARMS to add capacity (with no capital charge) for crude distillation, fluid cat cracking, distillate hydrocracking; and then set limits on capacity 2% higher. Increased capacity by 8% (1% per year) from the Calibration Case for coking, gas oil hydrocracking, alkylation, pen/hex isomerization, distillate desulfurization, benzene saturation, hydrogen, and lube oil. As in the 2002 Reference Case: (1) allowed ARMS to add capacity (with no capital charge) for debutanization, light naphtha splitting, naphtha and reformer feed desulfurization, distillate dearomatization, and FCC naphtha splitting; and then set limits on capacity 5% higher (except for naphtha and reformer feed desulfurization and distillate dearomatization, which are left unconstrained); and (2) held capacity constant for dimersol, polymerization, reforming, MTBE, TAME FCC naphtha desulfurization, butane isomerization, and solvent deasphalting. As in the 2002 Reference Case, this procedure allows most process units (with the exceptions noted above) some degree of slack, generally ranging from about 2 to 5%.

Adjusting the capital stock in this manner led to Reference Cases in which: (1) the aggregate California refining sector fully supplies projected refined product demands (i.e., no imports of finished products); (2) the marginal costs of producing refined products are similar to those in the Calibration Case; and (3) the refinery system has some slack, permitting small increases in refined product output before capacity constraints are reached and marginal production costs begin increasing. We sought these results in the Reference Cases so that the results of the Supply Scenarios would reflect only the cost of a MTBE ban and not any costs of meeting

normal demand growth.[2]

2.2 Reference Case Results

The results for the 2002 Reference Case (Intermediate term, MTBE,1A & 1F) and the 2005 Reference Case (Long term, MTBE,1A & 1F) are shown in Exhibits 5 through 9. (The cases designated as 1A employ the Predictive Model in averaging mode; the cases designated as 1F employ the Predictive Model in flat limits mode.) The results are similar to those previously reported for the Calibration Case, except for increases in product out turns and capacity utilization. The exhibits are as follows.

- **Exhibit 5 (pages 1 & 3)** shows process unit utilization and operations.

- **Exhibit 6A (pages 1& 3)** shows refinery inputs.

- **Exhibit 7 (pages 1 & 2)** shows refinery production of refined product outputs.

- **Exhibit 8 (pages 1 & 4)** shows the properties of CARB, Arizona, and conventional gasoline and the % emissions calculated using the Predictive Model (not the reduced form incorporated in ARMS). Applying the Predictive Model (in averaging mode) to the 1997 summer CEC gasoline quality survey data yields the following % emissions: VOCs -- -0.61; NOx -- -0.49; and toxics -- -0.73. In this analysis, we use a target minimum for % emissions of –0.30 for the Predictive Model in averaging mode, under the assumption that over time refiners would fine tune their operations and move somewhat closer to the Predictive Model emission constraints.[3] We set a target minimum of –0.50 for % emissions for cases in which the Predictive Model is used in the flat limit mode, based on information developed by CEC and discussed in Section 3.2.

- **Exhibit 9 (pages 1 & 4)** shows the composition of CARB, Arizona, and conventional gasoline.

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[2] Other analytical procedures could be used to establish the Reference Cases. For example, they could be developed by assuming no "capacity creep." Instead, ARMS could be used to determine the optimal combination of investment in new process capacity and imports of blendstocks and refined products to meet projected product demands. The addition of new process capacity would be influenced by the investment costs specified for incremental capacity expansions -- investment costs could range from a fraction of to the full amount of the investment costs in ARMS for new units. Imports of blendstocks and finished products would depend on the supply curves for such materials and the extent of addition of new process capacity.

This procedure would lead to Reference Cases in which: (1) part of the projected product demands *might* be satisfied by imports; (2) the marginal costs of producing refined products are higher than in the Calibration Case; and (3) the refinery system has no slack permitting small increases in refined product output before capacity constraints are reached and marginal production costs begin increasing. It is likely that establishing the Reference Cases in this way would increase the effects and costs of an MTBE ban in the intermediate term.

[3] Modifying the Predictive Model minimum emission targets from those calculated for Summer 1997 to –0.30 tends to reduce the costs estimated for an MTBE ban

3. SUPPLY SCENARIOS

MTBE is a key blendstock enabling California refineries to produce gasoline meeting the stringent requirements of the Predictive Model. California refineries have configured their process capacity and operations to accommodate the use of MTBE as a gasoline blendstock.

The California refining sector's response to a ban on the use of MTBE as a gasoline blendstock would be influenced by: (1) the techno-economics of current refinery operations; (2) the extent to which new process capacity is brought on-line in response to an MTBE ban; (3) the availability and price of alternative oxygenates (e.g., ethanol, TBA, ETBE, and TAME); (4) the availability and price of various refined products (e.g., jet fuel and diesel fuel) and blendstocks (e.g., CARBOB, alkylate, and distillate) that could be used to facilitate the production of or supplement the supply of refined products for the California market; and (5) the ability of refineries to sell blendstocks that would be rejected from gasoline blending (at certain market prices) because of the emission reduction requirements of the Predictive Model.

Assessing the California refining sector's likely response of an MTBE ban is a difficult undertaking. Indeed, the CEC has specified over 60 distinct Supply Scenarios as part of the effort to evaluate the potential effects of an MTBE ban. Because of the complexity of refining operations and the interplay of multiple technical and economic factors, any comprehensive effort to evaluate the effects of an MTBE ban of necessity must rely on a comprehensive refinery LP model, such as ARMS, that:

- Adequately represents refining operations under current regulatory standards;
- Incorporates the techno-economics of the most important refining processes, along with the flexibility of the refining sector to modify process operations in response to new circumstances;
- Represents the constraints imposed by the Predictive Model on gasoline blending;
- Allows for various responses to an MTBE ban -- such as importing desirable blendstocks, CARBOB, and finished products, and exporting undesirable blendstocks -- that are not now practiced because they are uneconomic under the current regulatory regime; and
- Has the flexibility to represent the sets of assumptions CEC has used to define each of the Supply Scenarios.

This section briefly discusses: (1) the enhancements we made to ARMS to allow representation of each of the Supply Scenarios and to capture the interaction of technical and economic factors influencing the refining sector's likely response to an MTBE ban; (2) operating modes (averaging or flat limits) in the Predictive Model; (3) the approach for assessing the effects of an MTBE ban under each Supply Scenario; and (4) the results of a

first set of refinery model runs assessing certain Supply Scenarios.

The factors defining each of the Supply Scenarios examined -- replacement oxygenate, period of analysis, MTBE ban region, and other policies – are shown in **Exhibit 4**, along with a summary of the modeling assumptions used to configure ARMS

3.1 Enhancements to ARMS

To conduct the Supply Scenario analysis, we modified and enhanced ARMS as follows:

- Total refined product demand. Established constraints so that projected demand for selected refined products (CARB gasoline, jet fuel, CARB diesel fuel, and EPA diesel fuel) is equal to the sum of refinery production and imports.

- Oxygenate supply. Represented oxygenate supply functions (MTBE, ethanol, TBA, ETBE, and TAME) developed by ESAI.

- CARBOB supply. Represented CARBOB supply functions developed by Purvin & Gertz and established recipe blending of CARBOB with specified oxygenates. (We established three recipe blends for ethanol representing blending to 2.1, 2.7, and 3.5 wt% oxygen.)

- Alkylate supply. Represented alkylate supply functions developed by Purvin & Gertz and set the ratio of propylene alkylate and butylene alkylate in imported alkylate at 40/60. (Alkylate import volumes in the Supply Scenarios are in addition to alkylate imports volumes specified in the Reference Cases.)

- Other inputs.

  -- Represented isobutane supplies comprising a maximum of 12 K bbl/d of imports (the volume of inputs for Summer 1997 reported by CEC) at $22.19/bbl (the average reported price for Summer 1997) and unlimited imports at $24.36/bbl (about 13¢/gal higher than average reported Gulf Coast prices for Summer 1997).

  -- Allowed imports of isomerate as follows: 10 K b/d at $26/bbl, $27/bbl, and $28/bbl. Given Gulf Coast refining pen/hex isomerization capacity of about 170 K b/d, it is likely that limited volumes of isomerate could be supplied by Gulf Coast refineries to California. We estimated an initial supply price for isomerate by adjusting the Gulf Coast price of regular gasoline downward to account for the value of the octane differential between isomerate and regular gasoline and then adding about $4/bbl transportation costs and $1/bbl for miscellaneous costs and margin. We increased the price for larger supplies of isomerate to reflect increases in its marginal value to Gulf Coast refiners as it is removed from their gasoline pool.

-- Allowed distillate blendstocks imports at $25.50/bbl (about 9¢/gal higher than average reported Gulf Coast prices).

-- Allowed EPA diesel fuel imports at $25.80/bbl (about 9¢/gal higher than average reported Gulf Coast prices).

-- Allowed jet diesel fuel imports at $26.50/bbl (about 9¢/gal higher than average reported Gulf Coast prices).

- Oxygenate properties. Established three ethanol streams to distinguish the effects on gasoline distillation curves of blending ethanol to 2.1, 2.7, and 3.5 wt% oxygen.[4] Properties for the ethanol streams and other oxygenates are shown in Appendix A (at the end of this report).

- Predictive Model.

-- Added a reduced-form of the Predictive Model for CARB gasoline with oxygen content ranging from 2.2 to 3.5 wt%.

-- Added an option to run the Predictive Model in either averaging or flat limits mode.

- Export of rejected gasoline blendstocks. Allowed for the export of gasoline blendstocks at the following prices: mixed butylenes -- $12.00/bbl; pentanes -- $12.60/bbl; light coker naphtha -- $13.00/bbl; and light FCC gasoline, heavy FCC gasoline, virgin naphtha (250 – 325 °F) and heavy reformate -- $15.00/bbl.[5]

With these enhancements, we can configure ARMS to represent each Supply Scenario and can use it (as described in the next section) to find an "optimal solution" in which: (1) projected product demands are met with the lowest cost combination of refinery production (from crude oil, specified purchased inputs, and imports of blendstocks), imports of refined products (CARBOB blended with oxygenates, jet fuel, and diesel fuel), and sales of rejected blendstocks; and (2) requirements of the Predictive Model for CARB gasoline, requirements of the Complex Model for Arizona gasoline, and all other refined product specifications are met.

[4] The blending properties are developed in a memorandum entitled "Ethanol Blending Properties for Task 3 Modeling Work" from MathPro to Gordon Schremp, CEC, June 30, 1998.

[5] In situations where heavy reformate is rejected from the gasoline pool, refineries presumably would sell reformer naphtha feed, rather than incurring the cost of reforming the material and then rejecting reformate. We allowed ARMS to sell most heavy reformate feeds. However, in two intermediate term no oxygenate cases ARMS would reject virtually all heavy reformate feeds and, because we did not allow some heavy reformate feeds to be sold, ARMS rejects heavy reformate instead. This slightly increases the cost associated with the intermediate term no oxygenate cases.

3.2 Predictive Model Operating Modes

Refiners may use the Predictive Model in an averaging mode or in a flat limits mode. Further, the averaging mode may be used for some properties and the flat limit mode for others. In the averaging mode, refiners must use the measured properties of a given batch of gasoline when running the Predictive Model. In the flat limits mode, refiners specify per gallon limits on each (or a subset) of gasoline properties which the measured properties for a given gasoline batch must not exceed. Refiners may modify frequently the flat limits governing their gasoline production.

The Predictive Model, when run in the flat limit mode with CARB's specified flat limits and when run in the averaging mode with CARB's specified averaging limits, yields the same % emissions (at the specified limits, percent (%) emissions are zero).[6] The "deltas" between the CARB specified flat limits and averaging limits are as follows: aromatics – 3 vol%; benzene – 0.20 vol%; olefins – 2.0 vol%; sulfur – 10 ppm; T50 – 10 °F; and T90 – 10 °F. If the average properties of a gasoline pool diverge from CARB's specified averaging limits, the Predictive Model yields different % emissions when run in the averaging mode -- with the average pool properties -- and in the flat limits mode -- with the average pool properties plus each of the above deltas. This is shown in the table below, where: (1) the average gasoline properties differ from CARB's specified averaging limits; and (2) the flat limit properties differ from average properties by the above deltas. The difference in % emissions is most marked for aromatics. This behaviour required us to estimate new reduced-form versions of the Predictive Model when run flat limits mode.

In general, refiners may use the flat limit mode to their advantage if they can establish flat limits that are closer to measured properties for gasoline batches than the deltas reported above. Further, the closer refiners can bring actual measured gasoline properties to the flat limits, the greater the advantage to using the flat limit mode.

At our request, CEC undertook an analysis of the flat limits reported by refiners and compared them to the average gasoline properties reported by the same set of refiners in the CEC gasoline survey. Shown below is the weighted average difference between each flat limit and average gasoline property by grade and for the entire gasoline pool (i.e., flat limit minus average property) and % emissions corresponding to the set of weighted average reported flat limits, by grade.

[6] CARB's specified averaging limits are as follows: aromatics – 22.0 vol%, benzene – 0.80 vol%, olefins – 4.0 vol%, sulfur – 30 ppm, T50 – 200 °F, and T90 – 290 °F. CARB's specified flat limits are as follows: aromatics – 25.0 vol%, benzene – 1.00 vol%, olefins – 6.0 vol%, sulfur – 40 ppm, T50 – 210 °F, and T90 – 300 °F.

Computed Emissions for Flat Limit and Averaging Modes

	Flat Limits	Measured Properties
Properties		
RVP (psi)	6.8	6.8
Oxygen (wt%)	2.1	2.1
Aromatics (vol%)	24.0	21.0
Benzene (vol%)	0.80	0.60
Olefins (vol%)	5.5	3.5
Sulfur (ppm)	35	25
T50 (°F)	205	195
T90 (°F)	295	285
Mode	Flat Limits	Averaging
% Emissions		
VOCs	-2.62	-1.71
NOx	-.37	-.35
Toxics	-6.49	-6.38

Reported Differences Between Flat Limits and Average Properties and % Emissions

	Premium	Regular	Pool
Flat Limit minus Average Property			
Aromatics	2.2	1.8	1.9
Benzene	0.25	0.13	0.15
Olefins	2.3	1.7	1.8
Sulfur	4.8	5.0	5.0
T50	4.6	4.9	4.8
T90	8.5	7.1	7.4
% Emissions			
VOCs	-0.76	-0.77	
NOX	-0.44	-0.25	
Toxics	-0.99	-0.62	

Based on these results, we developed a flat limit operating mode for the Predictive Model in which flat limits are higher than average properties calculated in ARMS by the deltas shown above for the entire gasoline pool. We also set target minimums for emissions at –0.50 based on the above calculations and discussions with refiners regarding operational capabilities.

With this specification, the primary advantage of using the Predictive Model in the flat limits mode is for T50 control.

3.3 Methodology

The analytic approach for conducting the refinery modeling of the Supply Scenarios was as follows.

- Supply curves. We changed the oxygenate, CARBOB, and alkylate supply curves from scenario to scenario to reflect the factors defining each Supply Scenario (e.g., the replacement oxygenate, the time period of analysis, the MTBE ban region, the availability of ethanol incentives, etc.).

  We used the same supply curves for isomerate, distillate blendstocks, jet fuel, and EPA diesel fuel across all Supply Scenarios.

- Period of analysis. Modeling of all intermediate term Supply Scenarios is based on the 2002 Reference Case. In the intermediate term, only minor capacity expansions, such as through debottlenecking, are allowed. We model this assumption by allowing up to a 5% increase in capacity (with full investment costs) for existing units, but no capacity additions beyond that and no additions of new units. Modeling of all long term Supply Scenarios is based on the 2005 Reference Case. In the long term scenarios, refining capacity is added as needed at full investment cost.

- RVP Adjustments.

  In the “no ethanol RVP waiver cases,” we set the RVP constraints for CARB RFG to 5.5 psi and the RVP of ethanol to 5.5 psi. Given the 1.3 psi increase in RVP associated with blending ethanol into 5.5 psi gasoline, the RVP of the finished ethanol-blended CARB RFG would be about 6.8 psi.

  In the “1 psi RVP waiver cases,” we set the RVP constraints for CARB RFG to 6.5 psi and the RVP of ethanol to 6.5 psi. Assuming a 1.3 psi increase in RVP associated with blending ethanol into 6.5 psi gasoline, the RVP of the finished ethanol-blended CARB RFG would be about 7.8 psi.

  In the “ethanol/business as usual/national MTBE ban cases,” we assume that ethanol would be blended in Arizona RFG. We modified the coefficients of the reduced form of the Complex Model such that a RVP of 5.5 psi corresponds to 6.8 psi in terms of

emission reductions.

- TBA, ETBE, and Mixed Oxygenate Cases. We allowed the replacement oxygenate(s), along with MTBE, to be blended in Arizona and conventional gasoline.

- Alkylate supply. We modified the volume of alkylate available in several ethanol cases to investigate the sensitivity of modeling results to changes in prospective alkylate supply. In particular, we ran cases in which the supply of imported alkylate was limited to 175 K bbl/d, 50 K bbl/d, and 100 K bbl/d. Alkylate supply for other "California MTBE Ban" cases and "National MTBE Ban" cases were limited to 100 K bbl/d and 75 K bbl/d, respectively.

- Ethanol blending. For all cases in which ethanol receives a tax credit, we assume that ethanol blending would be either at 6 vol% (2.1 wt% oxygen) or 7.8 vol% (2.7 wt% oxygen), because the tax credit is available only for ethanol blended at those specified percentages. To determine the extent of ethanol blending in a given Supply Scenario, we ran (at least) two cases: one in which the oxygen content of CARB RFG was constrained to 2.1 wt%, the other in which it was constrained to 2.7 wt%. Comparison of the objective functions for the two cases indicated the preferred level of ethanol blending.

  We also ran variants for the intermediate and long term in which we assumed a continuous ethanol tax credit is available to refiners, i.e., ethanol could be blended anywhere from 2.2 to 2.7 wt% oxygen. ARMS blended ethanol to 2.7 wt% oxygen in both cases.

- Imports of CARBOB. Because of modeling complexities presented by the Complex and Predictive Models, ARMS is set up so that the volume of refinery gasoline production must be specified. CARBOB (adjusted for oxygenate blending) is then imported to make up the difference between refinery gasoline out turns and demand. Thus, we conducted a series of iterative model runs for each ethanol Supply Scenario to determine the "optimal" combination of refinery production of CARB RFG and imports of CARBOB. (The number of runs could be as few as two for cases in which no CARBOB imports were called for.)

- Predictive Model % Emissions. Because ARMS incorporates a reduced form of the Predictive Model, not the actual model, the % emissions calculated in ARMS for a given set of gasoline properties may differ somewhat from the % emissions calculated using the Predictive Model for the same set of gasoline properties. To resolve discrepancies, we ran ARMS iteratively, generally twice, such that % emissions calculated with the Predictive Model closely matched the minimum targets (-0.30 or –0.50 depending on the operating mode) for at least on type of emission.

3.4 Results of Model Runs

The results of model runs for each of the Supply Scenarios are shown in **Exhibits 5 to 9.**

Exhibit 10 provides a summary of key results for each of the cases in terms of costs, investment, imports of blendstocks and refined products, sales of rejected blendstocks, and capacity utilization rates. This Exhibit include several cost categories:

- **Variable cost** equals the difference between the estimated cost in ARMS of supplying projected refined product demand in the Reference Case and the various Supply Scenario cases, not including any capital charges, ancillary costs, or infrastructure costs. Factors accounted for in this cost category are operating costs; costs of crude oil inputs, imported blendstocks, and imported refined products; sales of rejected blendstocks; and energy purchases.

- **Refinery capital charges** are the annualized costs associated with investments made by refineries to expand or add new refining process capacity.

- **Ancillary refining costs** are costs that refineries may incur under an MTBE ban, but that are not registered in a refinery LP model (ARMS, in this instance). Refinery LP models do not register ancillary costs not because they are imaginary, but because it is hard to express them as explicit functions of refinery operating variables. The primary cost elements comprising ancillary costs in this study include additional blendstock tankage and inventory, over-optimization due to the profusion of blendstocks in ARMS, and over-optimization because of the use of an aggregate refinery model to represent the California refining sector. Ancillary costs are estimated as 0.1 ¢/gal (for blendstock tankage and inventory) plus 15% of variable costs and capital charges. Thus, ancillary costs are roughly proportional to refining costs calculated in ARMS for each Supply Scenario and are highest for the highest cost scenarios.

- **Logistics costs** are the annualized terminal and transportation costs associated with ethanol blending.

- **Mileage loss** is the cost of producing and distributing (not including federal or state taxes) the additional gasoline needed because of the mileage loss, if any, of replacing MTBE with alternative oxygenates. We assume the mileage loss is directly proportional to changes in gasoline energy density.

The results of the analysis indicate, *given assumptions regarding supply and demand curves*, that: (1) in the long term, allowed the opportunity to modify operations and invest in new capacity, the refining sector could shift to alternative oxygenates with modest cost increases; (2) in the intermediate term, shifting to ethanol is costly and disruptive to refining operations; (3) in the intermediate term, shifting to ethanol is more costly than shifting to other oxygenates; (4) passage of H.R. 630 would be beneficial to refiners; and (5) use of the Predictive Model in flat limits mode reduces the cost associated with shifting to alternative

oxygenates or using no oxygenate. We discuss selected Supply Scenarios in more detail below.

Ethanol cases in which HR 630 is assumed to be passed have results that are the same as in scenarios in which a minimum of 2.1 wt% oxygen is required. Our analyses indicate that the combination of the RVP effect of ethanol on gasoline (which is roughly invariant with respect to the percentage of ethanol blended in gasoline), the estimated laid in prices of ethanol to California refineries, and the attributes of the Predictive Model are likely to lead refiners to blend ethanol up to the maximum allowed in the Predictive Model (2.7 wt% oxygen), if ethanol is selected as the replacement oxygenate.

Ethanol cases in which the RVP waiver applies to CARB RFG are shown as infeasible under the averaging mode in the Predictive Model for both the intermediate and long term and as feasible, but high cost, under the flat limit mode in the Predictive model for the intermediate term. The reason for infeasibility under the averaging mode is that the Predictive Model shows a very large NOx penalty for high oxygen content (3.5 wt%) gasoline. Under the Predictive Model in averaging mode, a complying gasoline with 3.5 wt% oxygen must have a sulfur content of around 10 ppm, an olefin content of less than 1.0 vol%, *and* an aromatics content of less than 15 vol%. ARMS cannot "produce" adequate volumes of gasoline with these extraordinary properties. It also is unlikely that significant volumes of imported, CARB-compliant CARBOB would be available for blending with ethanol to 3.5 wt% oxygen.

Under the flat limit mode, ARMS can "produce" complying gasoline, primarily because the flat limits mode allows higher aromatics content (around 23 vol%). However, the complying gasoline "produced" by ARMS has an olefins content of less than 1.0 vol% and a sulfur content of less than 10 ppm. The primary source of sulfur and olefins in gasoline is FCC naphtha. Hence, to produce a gasoline with extremely low sulfur and olefins content would require refiners either limit the volume of FCC naphtha blended to gasoline or to further reduce the sulfur and olefins content of FCC naphtha. Our aggregate model of the California refining sector combines two different types of treatment trains now used to control the sulfur and olefins content of FCC naphtha: the first is conventional hydrotreating of FCC feed, followed by hydrotreating FCC naphtha; and the second is deep hydrotreating of FCC feed, which results in a relatively low sulfur/olefins content FCC naphtha. Thus, it is likely that our aggregate refining model will exercise refining options that are unavailable to refiners with specific treatment trains for FCC feed and FCC naphtha.

To deal with this problem, we developed two additional refining models, identical in most respects, except that one incorporates conventional FCC feed hydrotreating and FCC naphtha hydrotreating and the other incorporates deep FCC feed hydrotreating. The results of our analyses for the intermediate term (flat limits) indicate that it would be costly and possibly infeasible for refineries that employ deep FCC feed hydrotreating to control gasoline sulfur and olefins content to produce complying gasoline. Our modeling indicates that it would be less costly for refineries with conventional FCC feed desulfurization and FCC naphtha desulfurization to produce complying gasoline. However, these results hinge on the presence of excess FCC naphtha hydrotreating capacity and are sensitive to the properties of treated

FCC naphthas. It may well be that specific refineries with this type of treatment train may be unable to produce complying gasoline. Also, it is not clear whether imports of complying CARBOB would be available in large volume.

STAFF REPORT

SUPPLY AND COST OF ALTERNATIVES TO MTBE IN GASOLINE

TECHNICAL APPENDICES

Ethanol Blending Properties
For Task 3 Modeling Work

OCTOBER 1998

CALIFORNIA
ENERGY
COMMISSION

Pete Wilson, ***Governor***

P300-98-013J

M E M O R A N D U M

Date: June 30, 1998

To: Gordon Schremp, California Energy Commission

From: Dave Hirshfeld & Jeff Kolb, MathPro Inc.

Subject: Ethanol Blending Properties for Task 3 Modeling Work

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After we complete the Reference Case runs (incorporating forecasts of long-term refined product demands), we will focus on policy scenarios in which ethanol is the oxygenate in CARB RFG.

The results of this set of cases will be substantially influenced by the blending characteristics assigned to ethanol. The most important of these are ethanol's effects on (1) the RVP and (2) the distillation curve of CARB RFG.

We have developed a new set of blending characteristics for ethanol, based on technical information obtained from the literature and from refiners. This memorandum presents those ethanol blending properties, which we propose to use in analyzing the policy scenarios involving ethanol.

To satisfy the project schedule, we need a fast review of this work by interested parties.

1. EFFECT ON RVP

Exhibit 1 and **Exhibit 3-A** show the effect of ethanol blending on the RVP of finished gasoline.

Exhibit 1 (based on data from the Coordinating Research Council (CRC)) shows that 10 vol% ethanol blending raises the RVP of the base blend by about 1.1 to 1.4 psi. The data indicate that the RVP effect tends to be slightly higher, about 1.3 to 1.4 psi, for base blends with low RVP (5.5 psi, as in a California base blend) than for base blends with RVP above 7 psi.

Exhibit 3-A (based on refiner-supplied information) shows the RVP effect of ethanol blending at various percentages for base blends with RVP of 5.5 to 5.7 psi. These data indicate that most of ethanol's RVP effect occurs at low ethanol concentrations – ethanol blending at a 5 to 6 vol% increases RVP by about 1.3 psi – and that additional ethanol

blending does not further increase (or may reduce) RVP.

Based on these data, we will assume that blending 6 vol% ethanol, which corresponds to a 2.1 wt% oxygen content of finished gasoline, or more, increases RVP by 1.3 psi. To implement this assumption, we will set the RVP of both finished CARB RFG and ethanol at 5.5 psi. This insures that the RVP of the base blend (CARBOB) is 5.5 psi and the RVP of the finished CARB RFG is 6.8 psi (when adjusted for the assumed RVP effect of ethanol blending of 1.3 psi).

2. EFFECT ON THE DISTILLATION CURVE

Exhibit 1 provides data on the distillation curves of six combinations of base blends and 10% ethanol-blended finished gasolines. The data in the upper part of Exhibit 1 show the temperatures at which various percentages of the gasolines are distilled off. For example, for #1 base blend, the T50 is 201° F, i.e., 50% is distilled off at 201° F. The data in the lower part of Exhibit 1 also trace out the distillation curves, but in terms of the percent of gasoline distilled off at specific temperatures. For example, for #1 base blend, the E200 is 49.2%, i.e., at 200° F 49.2% is distilled off. We translate the T values into E values (through linear interpolations) because distillation curves in our refinery model (ARMS) are specified in terms of E values.

Exhibits 2-A, B, and C graph the distillation curves for the #1, #2, and #3 combinations of base blends and 10% ethanol-blended finished gasolines. These three have RVPs closest to CARB RFG, and we have complete distillation curves for them.

These data indicate that ethanol blending:

- affects primarily the front end of the distillation curve, i.e., T50 and lower T values
- has its most substantial effect at T40 (and probably lower T values for heavy base blends) – the T40 reduction averages more than 30° F; and
- may have an effect at T50 that is weakly and inversely related to the T50 of the base blend, i.e., the T50 of the finished gasoline changes least for base blends with higher T50s. (However, the data for T30 and T40 are not consistent with an inverse relationship.)

The #4 combination in Exhibit 1 shows a T50 reduction of 33° F . However, this base blend and finished gasoline have RVP significantly higher than those of CARB base blends and CARB RFG. Comparison of weighted average distillation curves for 8.7 RVP gasohol and conventional gasoline (taken from gasoline surveys) indicates T50 reduction of 13° F for

premium and 48° F for regular. This comparison, however, is not between matched sets of base blend and gasohol; instead, it is between gasohols and finished conventional gasolines. Additionally, the RVP of the gasohol and conventional gasoline is higher than CARB RFG.

Exhibits 3-B, C, and D show (refiner-supplied) data on the changes in T10, T50, and T90 of base blends in response to blending increasing percentages of ethanol. The exhibits include data points for both regular and premium grades. (The original data do not indicate that changes in T10, T50, and T90 depend on the gasoline grade). We have removed anomalous observations from the data set.

These data indicate that the:

- **T10** declines quickly with ethanol blending, up to about 5 vol% ethanol, but blending ethanol in excess of about 5% has no further effect on T10, i.e., the T10 reduction reaches a maximum of about 16° F at 5% to 6% ethanol;

- **T50** appears to decline (somewhat non-linearly) with increasing ethanol blending (and the magnitude of the effect is *not* systematically related to the T50 of the base blend); and

- **T90** also appears to decline with increasing ethanol blending (but less than T10 and T50).

Using the data in Exhibit 1 and Exhibit 3, we developed relationships between ethanol concentration and changes in RVP, T10, T50, and T90. These relationships are shown as the solid lines in Exhibit 3.

3. ETHANOL PROPERTIES FOR ARMS

Exhibit 4 shows our estimates of the effects on gasoline properties of ethanol blending to 6%, 7.7%, and 10% (corresponding to oxygen contents of 2.1 wt%, 2.7 wt%, and 3.5 wt%), along with the corresponding properties for ethanol that will be inserted in the ARMS database. We developed these estimates as follows:

1. We began with the "delta properties" estimated for T10, T50, T90, and RVP at 6%, 7.7% and 10% ethanol blending. (The "delta properties" are consistent with the solid lines in Exhibit 3.)

2. We assumed that for each level of ethanol blending the finished gasoline would be the same and would have properties (T10, T50, T90, and other Predictive Model properties) consistent with those of CARB RFG in the Calibration Case. Although it is unlikely that finished gasolines would be the same for different levels of ethanol blending, this

assumption provides a standard starting point for this analysis and allows us to calculate how base gasoline (CARBOB) properties would change as the level of ethanol blending changes.

3. We applied the "delta properties" to the T10, T50, T90, and RVP of the finished gasoline to calculate those properties for the implied CARBOB at each level of ethanol blending.

4. We developed distillation curves for the CARBOBs and finished gasoline in terms of E values that: (1) are consistent with their T10, T50, and T90 values at each level of ethanol blending; (2) incorporate the large effect of ethanol blending on the distillation curve in the T30 to T40 range; and (3) yield internally consistent E values for "delta properties" and ethanol properties. (The E-values for ethanol are a function of the E value of the starting CARBOB and the delta E value, as indicated in the formula provided in Exhibit 4.) The distillation curves of the CARBOBs and finished gasolines, in terms T values and E values are shown in **Exhibits 5-A, 5-B, and 5-C**.

5. We calculated the oxygen, aromatics, benzene, olefins, and sulfur contents and octane of the CARBOB for each ethanol blending level.

6. For comparison purposes, we calculated the properties of a CARBOB for MTBE blending (at 2.1 wt% oxygen) consistent with the blending values already incorporated in ARMS for MTBE and the results of the Calibration Case. (The distillation curves are shown in **Exhibit 5-D**.)

4. IMPLICATIONS FOR ETHANOL SCENARIOS

The calculations and estimates presented here have several implications for modeling of the ethanol policy scenarios.

- Ethanol CARBOBs must have an RVP of 5.5 psi, significantly lower than the RVP of MTBE CARBOB.

- Ethanol CARBOB for 6% and 7.7% ethanol blending must have higher E200s than MTBE CARBOB to make similar finished gasoline, i.e., they must be lighter.

  Some interested parties have expressed the view that ethanol has a larger impact than MTBE on the T50 (and hence on the E200) of finished gasoline. Our analysis indicates that MTBE has the larger effect – at least for CARB RFG.

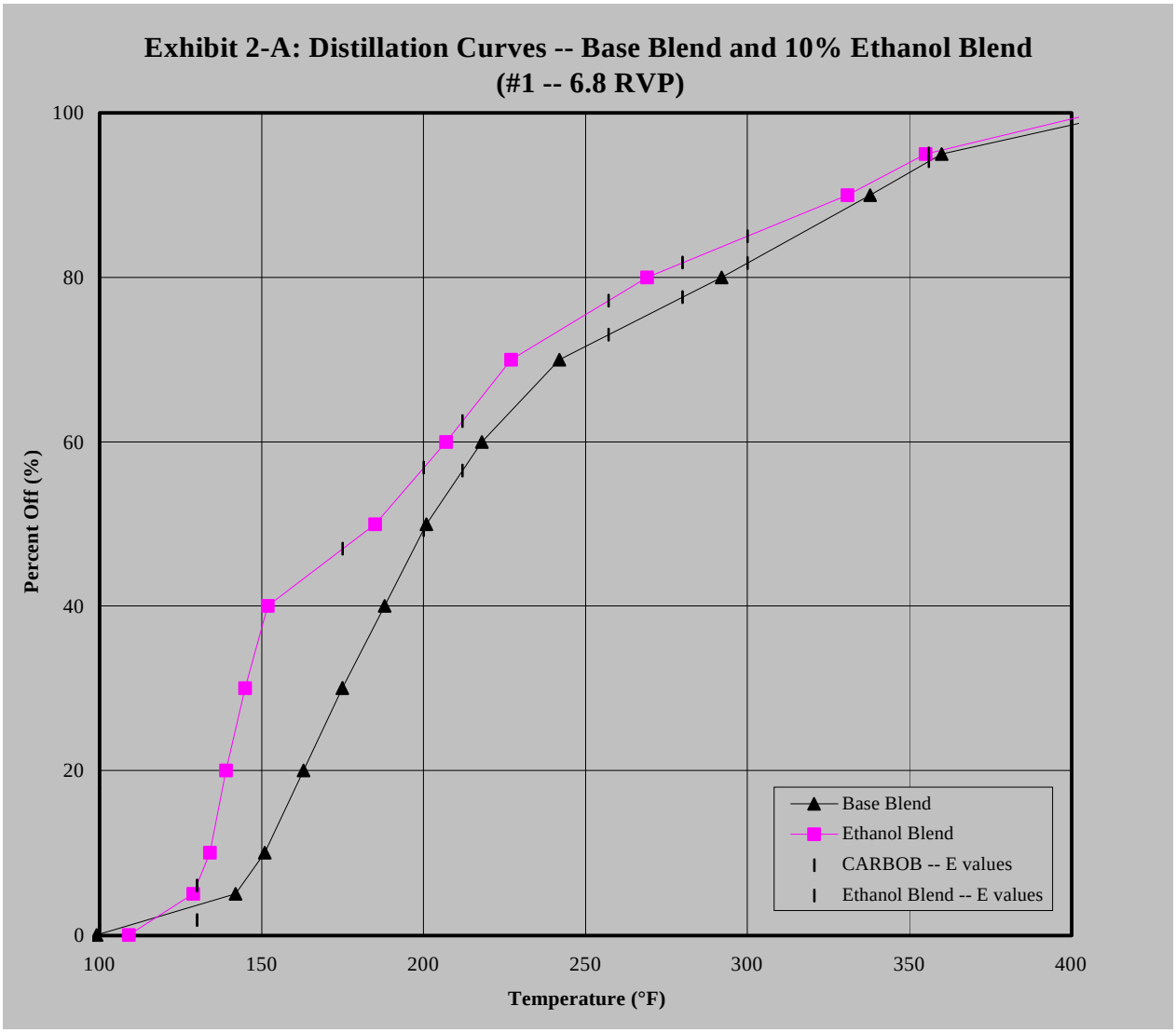
- All ethanol CARBOBs must have higher E300 than MTBE CARBOB to make similar finished gasoline.

- The aromatics and olefins levels of ethanol CARBOBs at 6% and 7.7% ethanol blending must be somewhat lower and the octane higher than MTBE CARBOB to make similar finished gasoline.

Exhibit 1: Distillation Curves for Base Blends and 10% Ethanol Blends -- CRC Publication

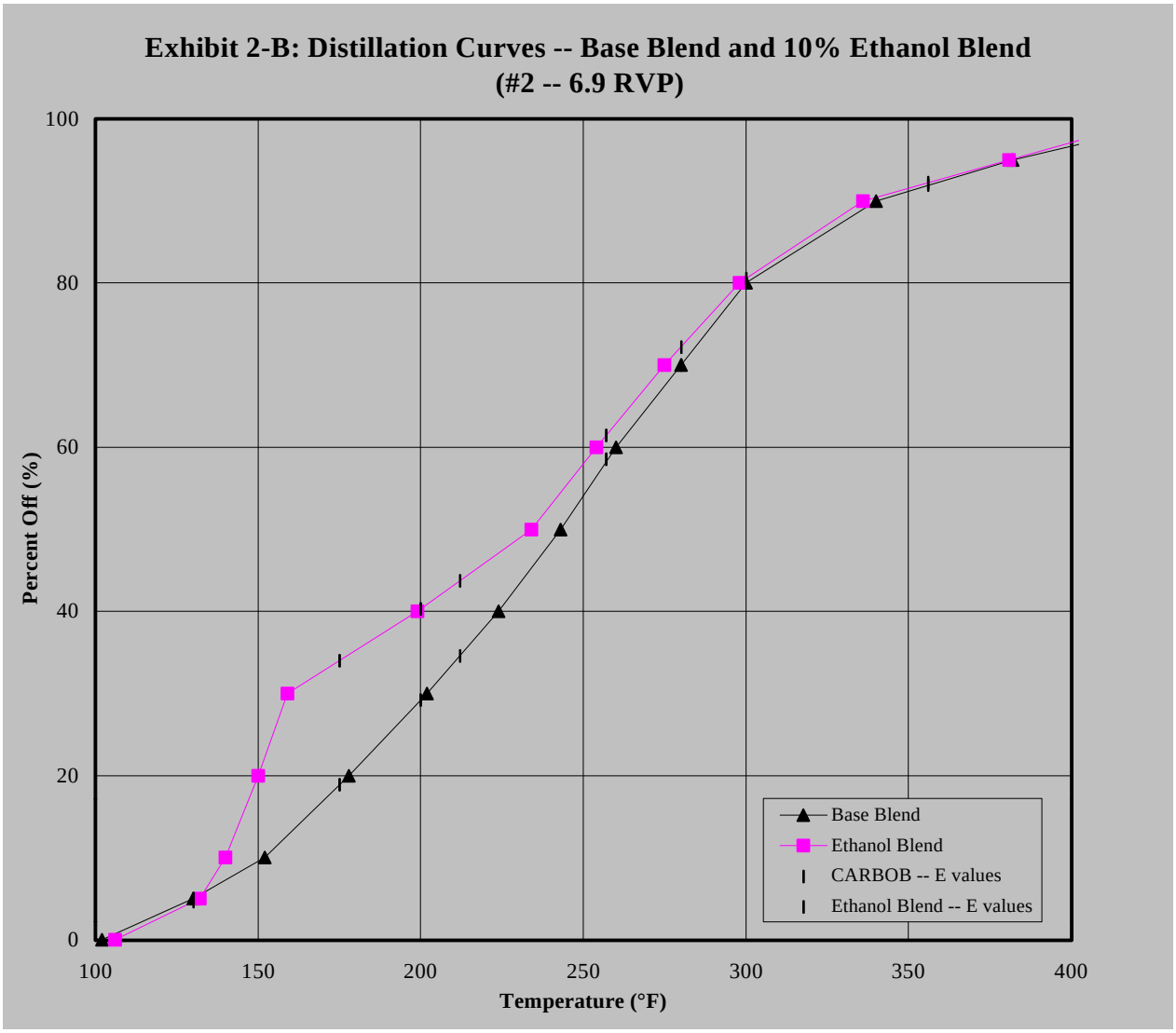
Distillation/ Property	Base Blend and Corresponding Ethanol Blend																	
	#1			#2			#3			#4			#5			#6		
	Base Blend	Ethanol Blend	Delta	Base Blend	Ethanol Blend	Delta	Base Blend	Ethanol Blend	Delta	Base Blend	Ethanol Blend	Delta	Base Blend	Ethanol Blend	Delta	Base Blend	Ethanol Blend	Delta
Temperature (°F) -->																		
IBP	99	109	10	102	106	4	83	95	12	91	83	-8	90	89	-1			
T5	142	129	-13	130	132	2	116	118	2	112	105	-7	108	106	-2			
T10	151	134	-17	152	140	-12	132	126	-6	118	116	-2	124	120	-4	142	133	-9
T20	163	139	-24	178	150	-28	153	137	-16	136	128	-8	158	139	-19			
T30	175	145	-30	202	159	-43	176	147	-29	158	140	-18	198	154	-44			
T40	188	152	-36	224	199	-25	200	159	-41	182	149	-33	228	177	-51			
T50	201	185	-16	243	234	-9	222	208	-14	203	170	-33	248	234	-14	242	234	-8
T60	218	207	-11	260	254	-6	238	233	-5	226	215	-11	267	257	-10			
T70	242	227	-15	280	275	-5	258	253	-5	248	239	-9	286	279	-7			
T80	292	269	-23	300	298	-2	288	283	-5	284	274	-10	305	300	-5			
T90	338	331	-7	340	336	-4	335	332	-3	338	332	-6	332	328	-4	355	351	-4
T95	360	355	-5	382	381	-1	363	366	3	368	364	-4	364	359	-5			
FBP	417	408	-9	436	426	-10	423	409	-14	419	416	-3	424	415	-9			
Percent Off (%) -->																		
E100	0.0	0.0	0.0	0.0	0.0	0.0	2.6	1.1	-1.5	2.1	3.9	1.7	2.8	3.2	0.5			
E130	1.8	6.0	4.2	5.0	4.6	-0.4	9.4	13.6	4.3	16.7	21.7	5.0	11.8	15.3	3.5			
E175	30.0	47.0	17.0	18.8	34.0	15.2	29.6	43.3	13.7	37.1	52.4	15.3	24.3	39.6	15.4			
E200	49.2	56.8	7.6	29.2	40.3	11.1	40.0	48.4	8.4	48.6	64.3	15.7	30.7	44.0	13.4			
E212	56.5	62.5	6.0	34.5	43.7	9.2	45.5	51.6	6.1	53.9	59.3	5.4	34.7	40.4	5.8			
E257	73.0	77.1	4.1	58.5	61.4	2.9	69.5	71.3	1.8	72.5	75.1	2.6	54.7	59.5	4.8			
E280	77.6	81.8	4.2	70.0	72.2	2.2	77.3	79.0	1.7	78.9	81.7	2.8	66.8	70.5	3.6			
E300	81.7	85.0	3.3	80.0	80.5	0.5	82.6	83.5	0.9	83.0	84.5	1.5	77.4	80.0	2.6			
E356	94.1	95.1	1.0	91.9	92.2	0.3	93.8	93.5	-0.2	93.0	93.8	0.8	93.8	94.5	0.8			
RVP (psi)	5.4	6.8	1.4	5.6	6.9	1.3	7.6	8.8	1.2	10.2	11.3	1.1	10.1	11.3	1.2	7.4	8.6	1.2
Ethanol (Vol %)	0	10		0	10		0	10		0			0			0	9.5	
Fuel Number	B	12		D	14		E	15		A	11		C	13		1	6	

Source: Combinations #1 - #5: CRC -- 578, March 1992; Combination #6+C6: CRC -- 585, August, 1993.



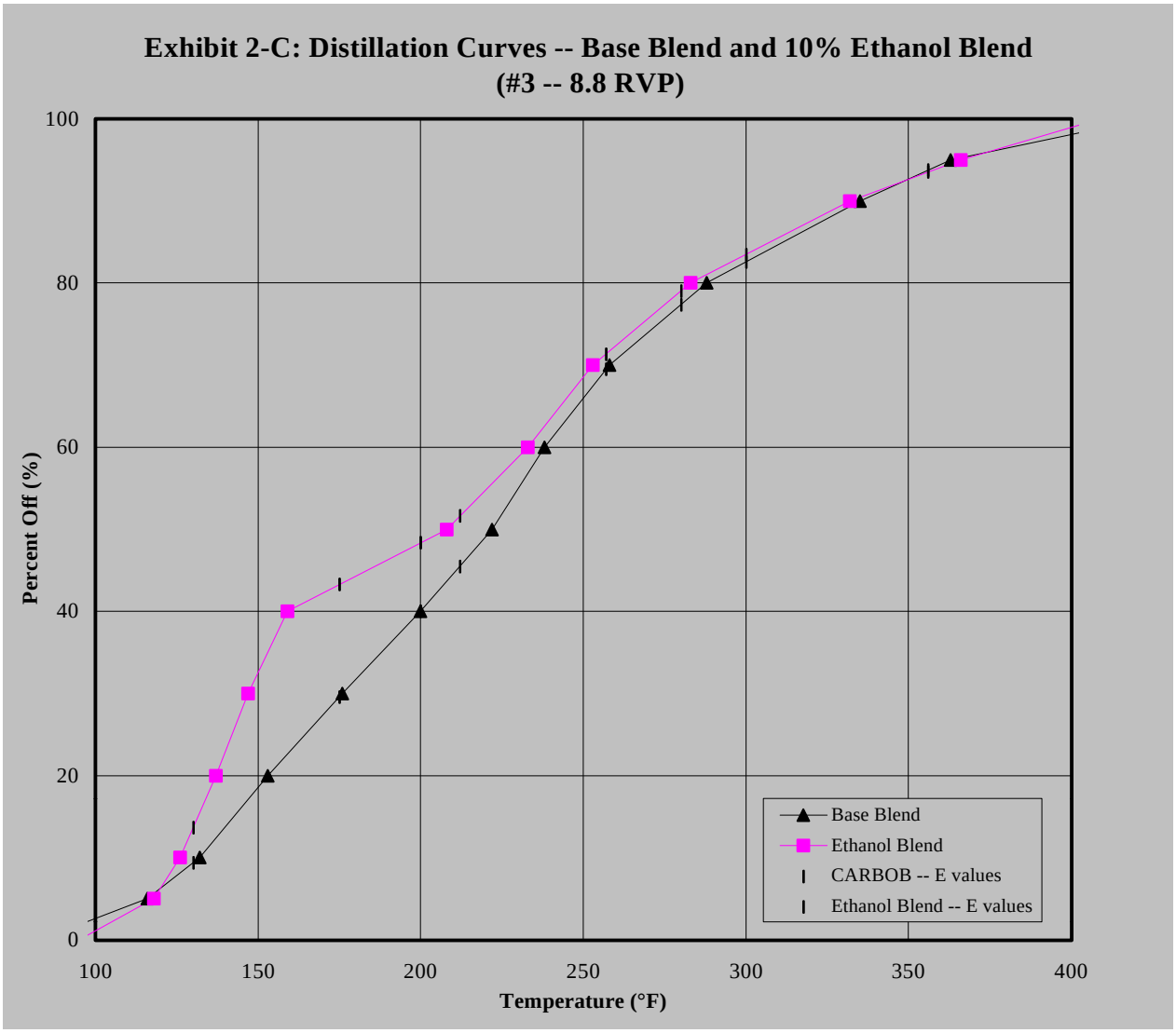
	°F				% Off		
% Off	Base Blend	Ethanol Blend	Delta	°F	Base Blend	Ethanol Blend	Delta
0	99	109	10	100	0.0	0.0	0.0
5	142	129	-13	130	1.8	6.0	4.2
10	151	134	-17	175	30.0	47.0	17.0
20	163	139	-24	200	49.2	56.8	7.6
30	175	145	-30	212	56.5	62.5	6.0
40	188	152	-36	257	73.0	77.1	4.1
50	201	185	-16	280	77.6	81.8	4.2
60	218	207	-11	300	81.7	85.0	3.3
70	242	227	-15	356	94.1	95.1	1.0
80	292	269	-23				
90	338	331	-7				
95	360	355	-5				
100	417	408	-9				
RVP (psi)	5.4	6.8	1.4				
Ethanol (Vol %)	0	10					

Source: CRC -- 578, March 1992.



	°F				% Off		
% Off	Base Blend	Ethanol Blend	Delta	°F	Base Blend	Ethanol Blend	Delta
0	102	106	4	100	0.0	0.0	0.0
5	130	132	2	130	5.0	4.6	-0.4
10	152	140	-12	175	18.8	34.0	15.2
20	178	150	-28	200	29.2	40.3	11.1
30	202	159	-43	212	34.5	43.7	9.2
40	224	199	-25	257	58.5	61.4	2.9
50	243	234	-9	280	70.0	72.2	2.2
60	260	254	-6	300	80.0	80.5	0.5
70	280	275	-5	356	91.9	92.2	0.3
80	300	298	-2				
90	340	336	-4				
95	382	381	-1				
100	436	426	-10				
RVP (psi)	5.6	6.9	1.3				
Ethanol (Vol %)	0	10					

Source: CRC -- 578, March 1992.



% Off	°F Base Blend	°F Ethanol Blend	°F Delta	°F	% Off Base Blend	% Off Ethanol Blend	% Off Delta
0	83	95	12	100	2.6	1.1	-1.5
5	116	118	2	130	9.4	13.6	4.3
10	132	126	-6	175	29.6	43.3	13.7
20	153	137	-16	200	40.0	48.4	8.4
30	176	147	-29	212	45.5	51.6	6.1
40	200	159	-41	257	69.5	71.3	1.8
50	222	208	-14	280	77.3	79.0	1.7
60	238	233	-5	300	82.6	83.5	0.9
70	258	253	-5	356	93.8	93.5	-0.2
80	288	283	-5				
90	335	332	-3				
95	363	366	3				
100	423	409	-14				
RVP (psi)	7.6	8.8	1.2				
Ethanol (Vol %)	0	10					

Source: CRC -- 578, March 1992.

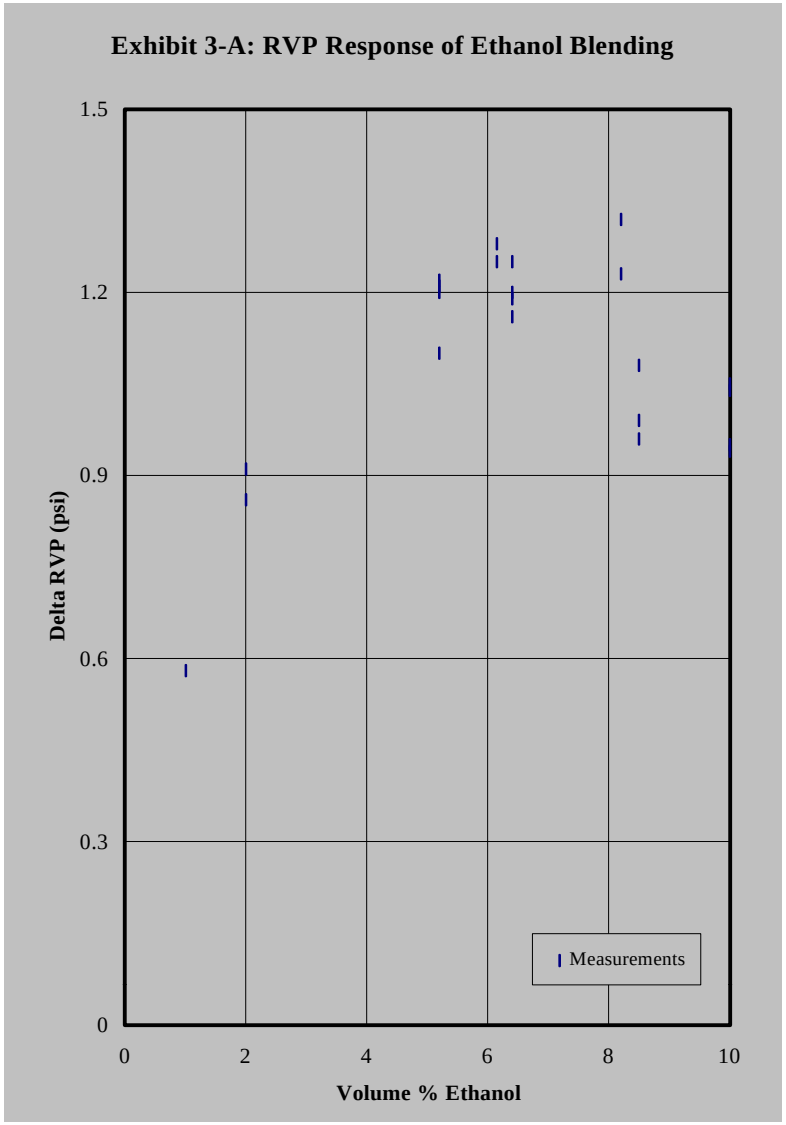


Exhibit 3-A: RVP Response of Ethanol Blending
Delta RVP (psi)
1.5
1.2
0.9
0.6
0.3
0
0
2
4
6
8
10
Volume % Ethanol
Measurements

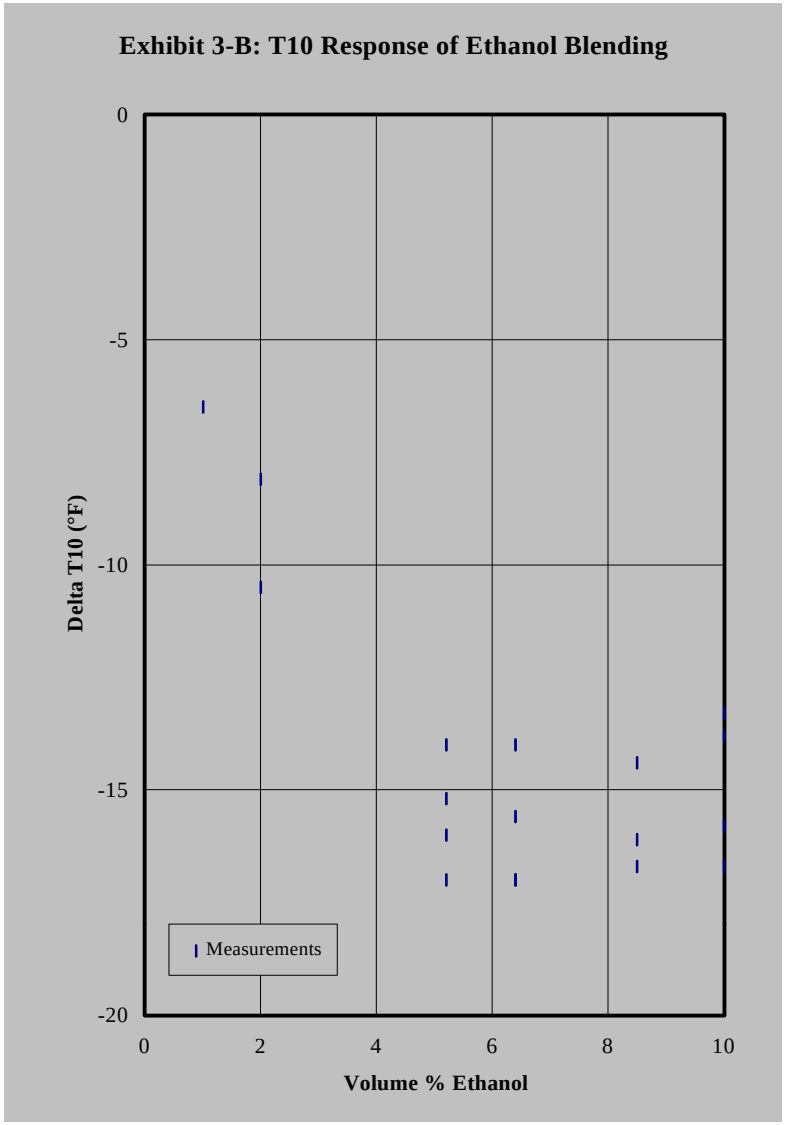


Exhibit 3-B: T10 Response of Ethanol Blending
Delta T10 (°F)
0
-5
-10
-15
-20
0
2
4
6
8
10
Volume % Ethanol
Measurements

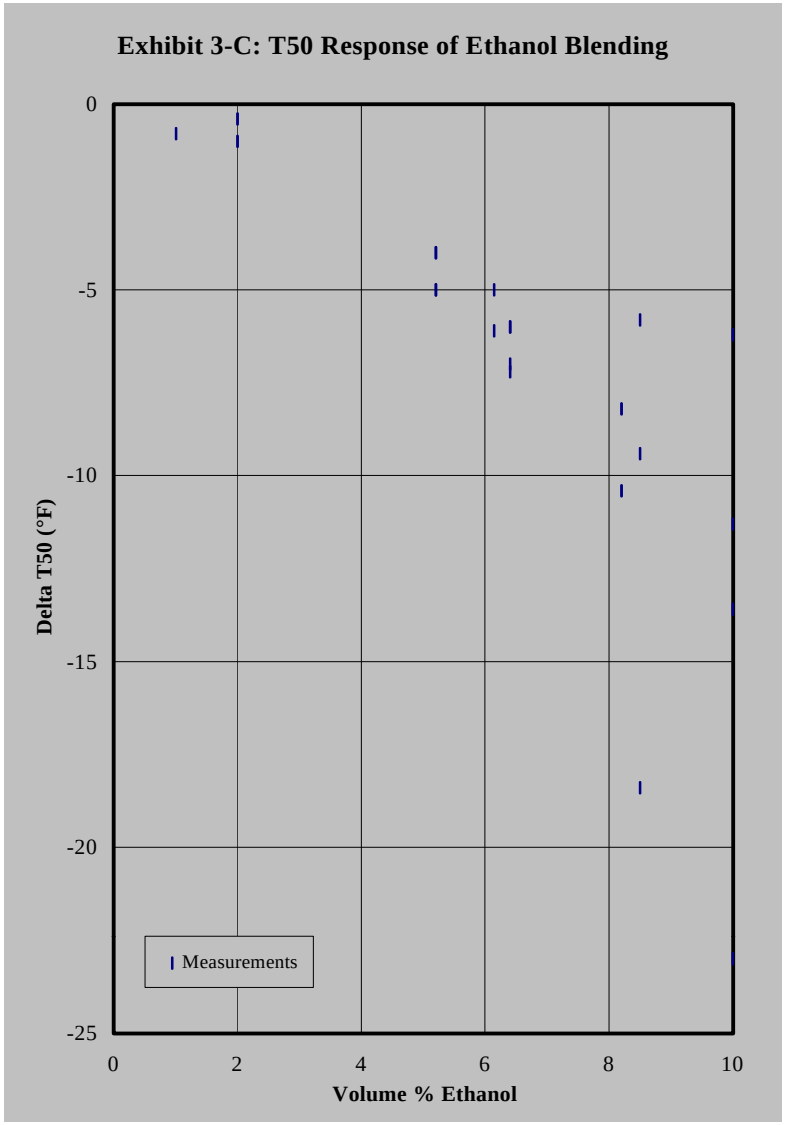


Exhibit 3-C: T50 Response of Ethanol Blending
Delta T50 (°F)
0
-5
-10
-15
-20
-25
0
2
4
6
8
10
Volume % Ethanol
Measurements

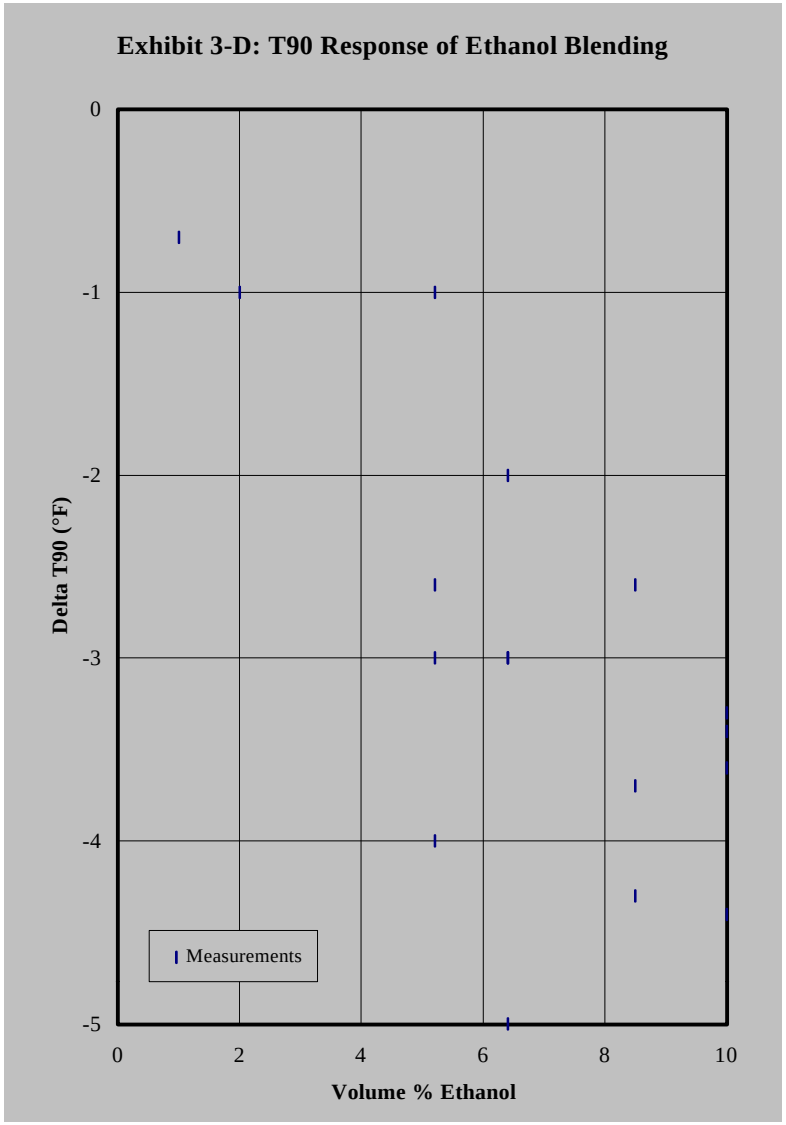
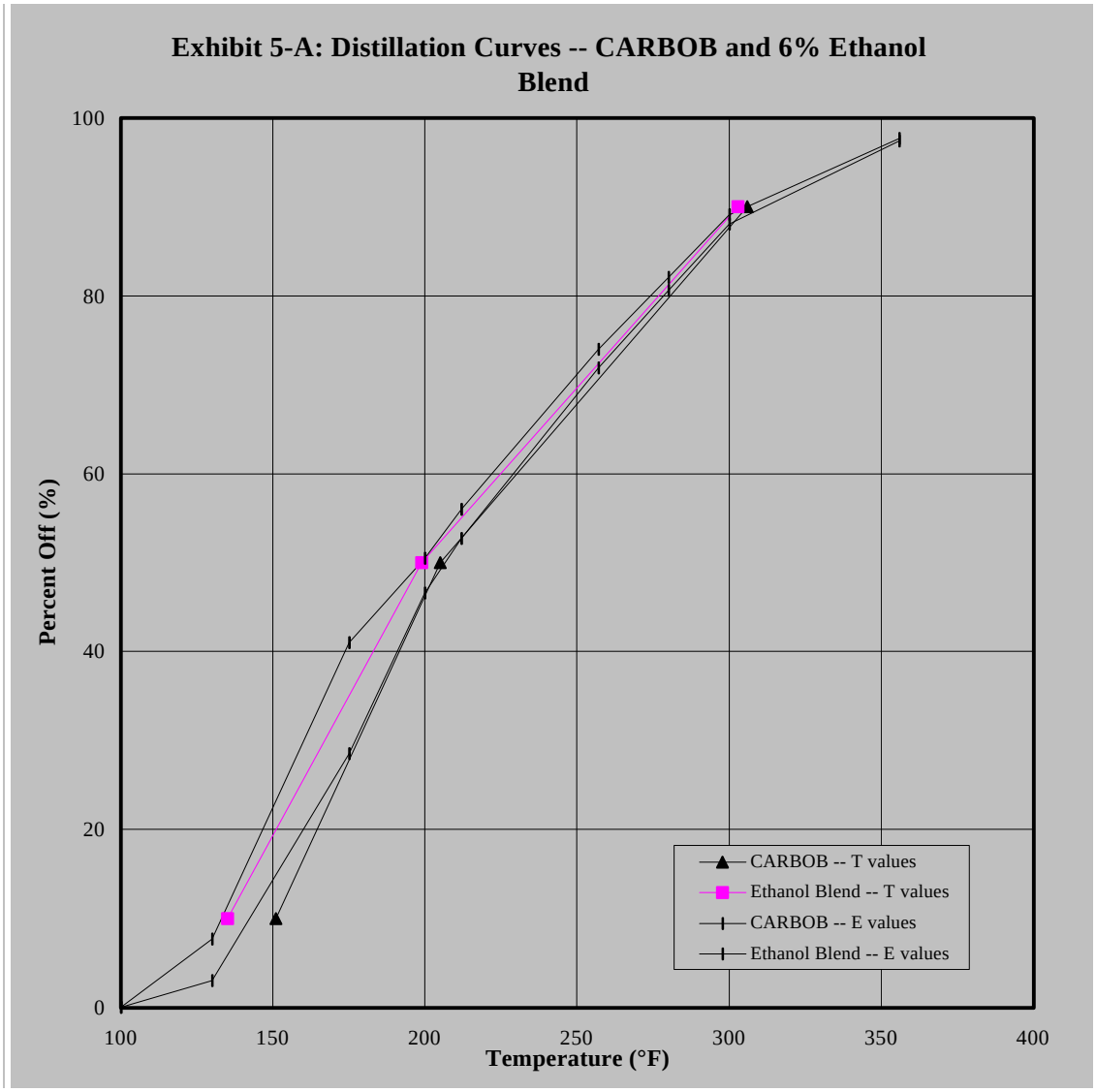


Exhibit 3-D: T90 Response of Ethanol Blending
Delta T90 (°F)
0
-1
-2
-3
-4
-5
0
2
4
6
8
10
Volume % Ethanol
Measurements

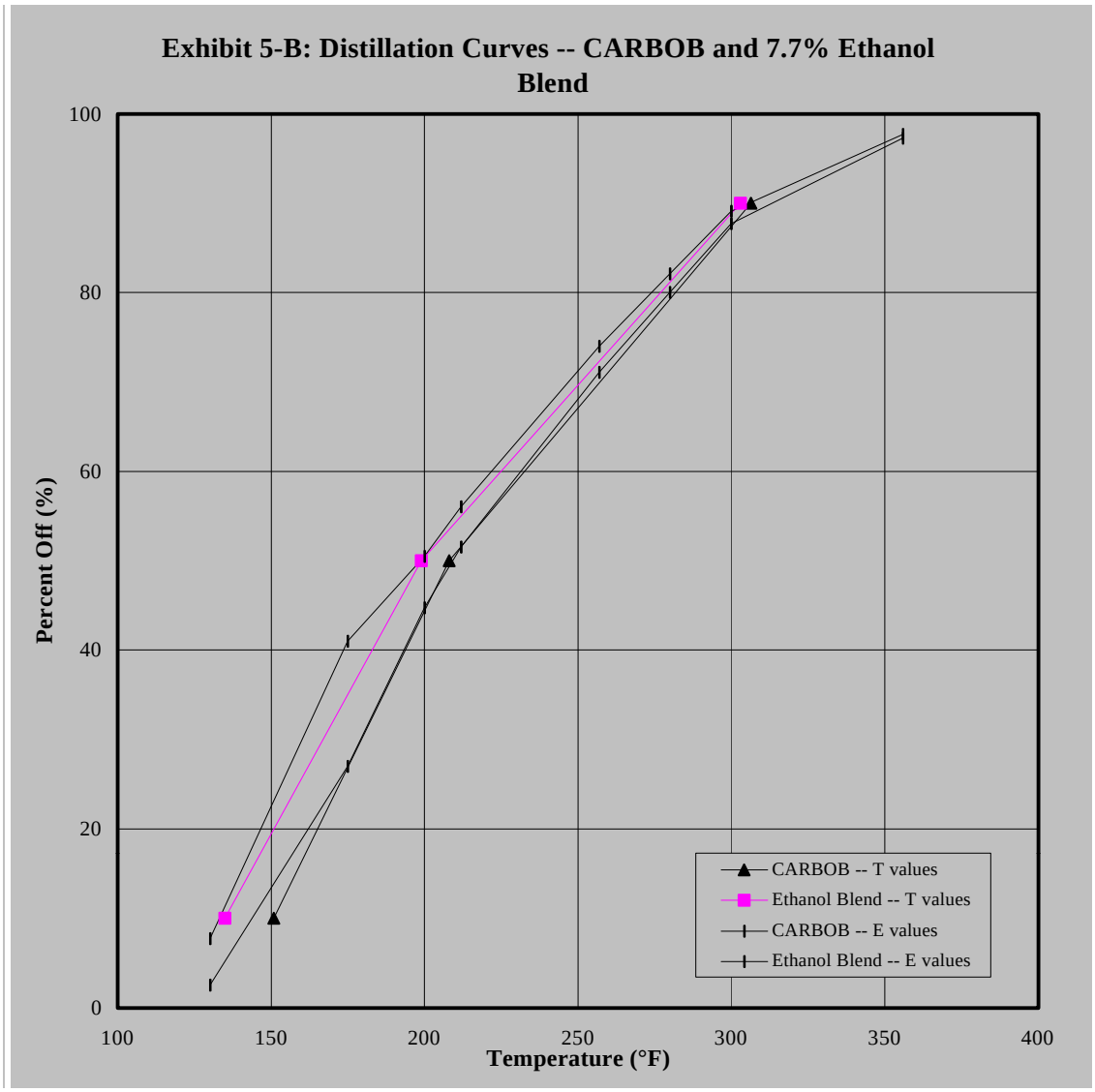
Exhibit 4: Estimated Effect on Gasoline Properties of Ethanol Blending and MTBE Blending

Volume %	T Values (°F)			Estimated E Values (% Off)									RVP	Oxy.	Arom.	Benz.	Olef.	Sulf.	Octane
& Blend	T10	T50	T90	E100	E130	E175	E200	E212	E257	E280	E300	E356	(psi)	(wt%)	(vol%)	(vol%)	(vol%)	(ppm)	((R+M)/2)
6% Ethanol																			
CARBOB	151	205	306	0	3.0	28.5	46.6	52.7	71.9	80.6	88.1	97.4	5.5	0.0	24.4	0.59	4.6	20.0	87.1
Finished	135	199	303	0	7.7	41.0	50.5	56.0	74.0	82.1	89.1	97.7	6.8	2.1	22.9	0.55	4.3	18.8	88.8
Delta Property	-16.0	-6.0	-3.0	0	4.7	12.5	3.9	3.3	2.1	1.5	1.0	0.3	1.3	-	-	-	-	-	-
Ethanol Property*				0	81.3	236.8	111.6	107.7	106.9	105.6	104.8	102.4	5.5	34.8	0.0	0.0	0.0	0.0	115.0
7.7% Ethanol																			
CARBOB	151	208	307	0	2.5	27.0	44.7	51.5	71.1	80.0	87.7	97.3	5.5	0.0	24.8	0.60	4.7	20.4	86.6
Finished	135	199	303	0	7.7	41.0	50.5	56.0	74.0	82.1	89.1	97.7	6.8	2.7	22.9	0.55	4.3	18.8	88.8
Delta Property	-16.0	-9.0	-3.5	0	5.2	14.0	5.8	4.5	2.9	2.1	1.4	0.4	1.3	-	-	-	-	-	-
Ethanol Property*				0	70.0	208.8	120.0	109.9	108.8	107.3	105.9	102.5	5.5	34.8	0.0	0.0	0.0	0.0	115.0
10% Ethanol																			
CARBOB	151	213	307	0	2.0	25.5	41.5	49.3	70.1	79.5	87.4	97.1	5.5	0.0	25.4	0.61	4.8	20.9	85.8
Finished	135	199	303	0	7.7	41.0	50.5	56.0	74.0	82.1	89.1	97.7	6.8	3.5	22.9	0.55	4.3	18.8	88.8
Delta Property	-16.0	-14.0	-4.0	0	5.7	15.5	9.0	6.7	3.9	2.6	1.7	0.6	1.3	-	-	-	-	-	-
Ethanol Property*				0	59.0	180.5	131.5	116.3	109.1	105.5	104.4	103.1	5.5	34.8	0.0	0.0	0.0	0.0	115.0
11.6% MTBE																			
CARBOB	149	215	309	0.9	5.8	25.8	42.4	48.3	68.9	78.2	86.2	96.0	6.6	0.0	25.9	0.62	4.8	20.0	86.0
Finished	135	199	303	1.5	7.7	35.2	50.5	56.0	74.0	82.1	89.1	97.7	6.8	2.1	22.9	0.55	4.3	18.8	88.8
Delta Property	-14.0	-16.0	-6.0	0.6	1.9	9.4	8.1	7.7	5.1	3.9	2.9	1.7	-	-	-	-	-	-	-
MTBE Property				6.0	22.0	107.0	112.0	115.0	113.0	112.0	111.0	111.0	8.0	18.2	0.0	0.0	0.2	10.0	110.0

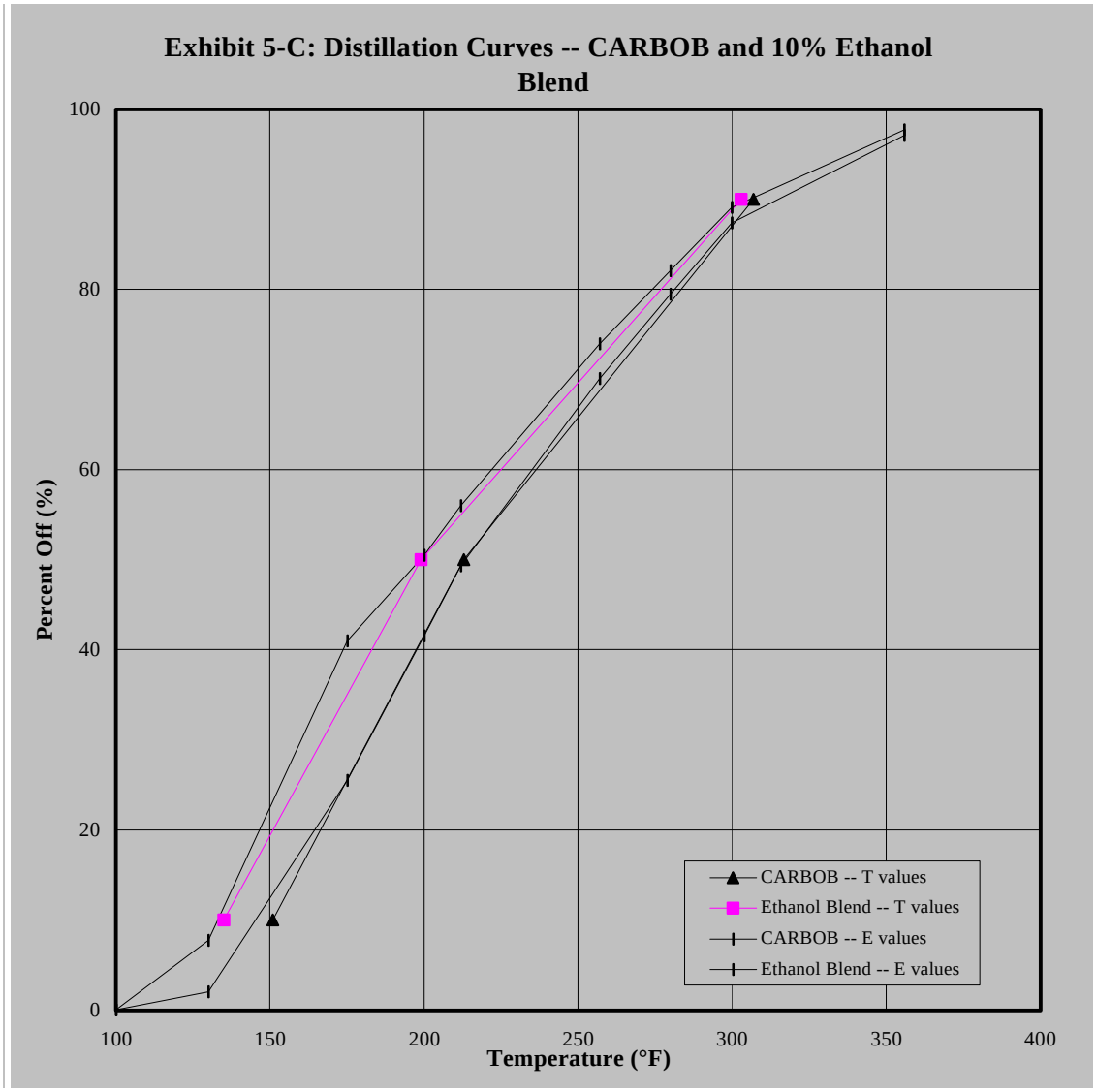
* The E-value for ethanol is given by the formula: E-TEMPethanol = E-TEMPcarbob + (Delta E-TEMP)/ (% Ethanol).



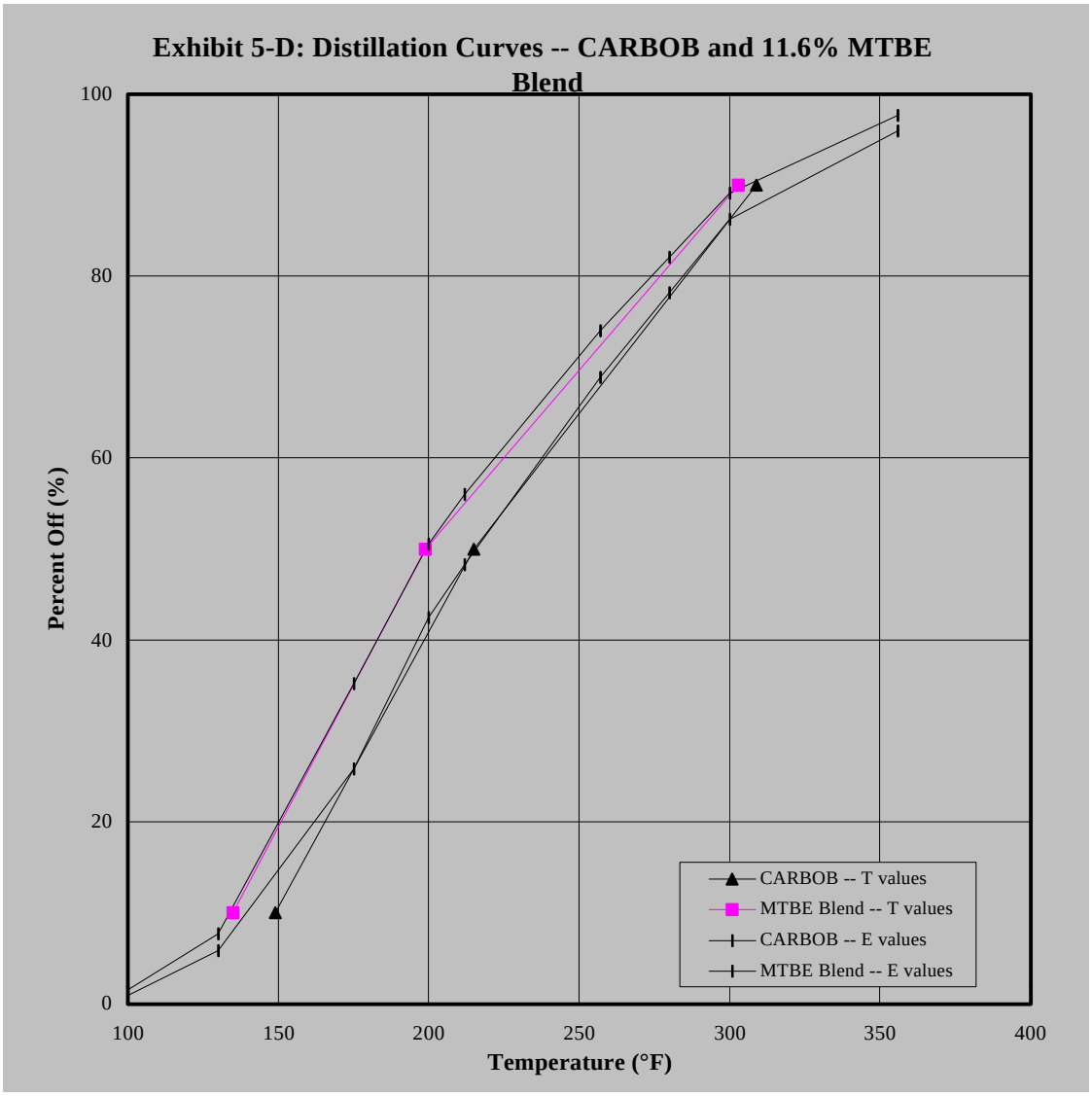
Blend	Percent Off by Temperature								
	100°	130°	175°	200°	212°	257°	280°	300°	356°
CARBOB	0.0	3.0	28.5	46.6	52.7	71.9	80.6	88.1	97.4
Finished	0.0	7.7	41.0	50.5	56.0	74.0	82.1	89.1	97.7
Delta	0.0	4.7	12.5	3.9	3.3	2.1	1.5	1.0	0.3
Ethanol	0.0	81.3	236.8	111.6	107.7	106.9	105.6	104.8	102.4



Blend	Percent Off by Temperature								
	100°	130°	175°	200°	212°	257°	280°	300°	356°
CARBOB	0.0	2.5	27.0	44.7	51.5	71.1	80.0	87.7	97.3
Finished	0.0	7.7	41.0	50.5	56.0	74.0	82.1	89.1	97.7
Delta	0.0	5.2	14.0	5.8	4.5	2.9	2.1	1.4	0.4
Ethanol	0.0	70.0	208.8	120.0	109.9	108.8	107.3	105.9	102.5



Blend	Percent Off by Temperature								
	100°	130°	175°	200°	212°	257°	280°	300°	356°
CARBOB	0.0	2.0	25.5	41.5	49.3	70.1	79.5	87.4	97.1
Finished	0.0	7.7	41.0	50.5	56.0	74.0	82.1	89.1	97.7
Delta	0.0	5.7	15.5	9.0	6.7	3.9	2.6	1.7	0.6
Ethanol	0.0	59.0	180.5	131.5	116.3	109.1	105.5	104.4	103.1



Blend	Percent Off by Temperature								
	100°	130°	175°	200°	212°	257°	280°	300°	356°
CARBOB	0.9	5.8	25.8	42.4	48.3	68.9	78.2	86.2	96.0
Finished	1.5	7.7	35.2	50.5	56.0	74.0	82.1	89.1	97.7
Delta	0.6	1.9	9.4	8.1	7.7	5.1	3.9	2.9	1.7
Ethanol	6.0	22.0	107.0	112.0	115.0	113.0	112.0	111.0	111.0

STAFF REPORT

SUPPLY AND COST OF ALTERNATIVES TO MTBE IN GASOLINE

TECHNICAL APPENDICES

Exhibits

OCTOBER 1998

CALIFORNIA ENERGY COMMISSION

Pete Wilson, *Governor*

P300-98-013K

EXHIBITS FOR

SUPPLY AND COST OF ALTERNATIVES TO MTBE IN GASOLINE

California Energy Commission

October 1998

EXHIBIT A

UPDATED INFORMATIVE DIGEST

Amendments To The
California Cleaner-Burning Gasoline Regulations

LIST OF EXHIBITS

A. Updated Informative Digest, Amendments to the California Cleaner-Burning Gasoline Regulations

B. Oxygenate Information Sheets

C. Federal Register Document, Change in Minimum Oxygen Content Requirement for Reformulated Gasoline

D. Bill Summary and Status for the 105th Congress, H.R. 630

UPDATED INFORMATIVE DIGEST

Amendments to the California Cleaner-Burning Gasoline Regulations

Sections Affected: Amendments to Sections 2260 to 2262.7 of Title 13, California Code of Regulations (CCR).

Background

The California Phase 2 reformulated gasoline (CaRFG) regulations were adopted by the California Air Resources Board (the Board or ARB) following a hearing in November 1991 and became applicable in the spring of 1996. The regulations establish a comprehensive set of standards for gasoline designed to achieve the maximum reductions in emissions of criteria pollutants and toxic air contaminants from gasoline-powered motor vehicles. The standards cover sulfur, benzene, olefin, oxygen, and aromatic hydrocarbon contents, the 50 percent and 90 percent distillation temperatures (T50 and T90), and Reid vapor pressure (RVP).

The CaRFG standards include "cap" limits that apply to finished gasoline throughout the California gasoline distribution system. The standards also include more stringent limits that apply to gasoline when it is the first supplied from a production facility (typically a refinery) or an import facility; these will be referred to as the "refiner" limits. The standards are as follows:

Property	Averaging Limit	Flat Limit	Cap
T50	200°F	210°F	220°F
T90	290°F (DAL not to exceed 310°F)	300°F	330°F
Olefins	4.0%	6.0%	10.0%
Aromatics	22.0%	25.0%	30.0%
Sulfur	30 ppm	40 ppm	80 ppm
Benzene	0.80%	1.00%	1.20%
Oxygen	None	1.8 wt%min to 2.2 wt%max	2.7 wt%max
RVP	None	7.00 psi	7.00 psi

Except in the case of RVP and oxygen content, the regulations provide two compliance options for meeting the limits applicable to gasoline being supplied from a production or import facility.

One option is to have the gasoline subject to a "flat limit," which must be met by every gallon of gasoline leaving the production or import facility. The other option is to elect an "averaging limit." The averaging limits established in the regulations for each of the six properties are more stringent than the comparable flat limits. Under the averaging option, the producer may assign differing "designated alternative limits" (DAL) to different batches of gasoline being supplied from the production or import facility. Each batch of gasoline must

meet the DAL for the batch. A producer or importer supplying a batch of gasoline with a DAL above the averaging limit must, within 90 days before or after, supply (from the same facility) sufficient quantities of gasoline subject to more stringent DALs to fully offset the excess over the averaging limit.

The CaRFG regulations also contain a compliance mechanism under which a producer or importer may use the "California Predictive Model" to identify alternative flat and averaging limits applicable when gasoline is supplied from the production or import facility. The Predictive Model provisions, which were adopted in 1994, consist of mathematical equations which estimate the changes in exhaust emissions of hydrocarbons, oxides of nitrogen (NOx), and four toxic air contaminants that result from different gasoline formulations. The four toxic air contaminants are benzene, 1,3-butadiene, acetaldehyde, and formaldehyde. An alternative gasoline formulation is acceptable if the percent change in emissions is less than or equal to 0.04 percent for hydrocarbons, oxides of nitrogen, and the potency-weighted sum of the toxic air contaminants. No alternative limit may exceed the cap limit for the property.

The standards for oxygen content are administered differently from the rest of the standards. In most cases, CaRFG-compliant gasoline must have an oxygen content between 1.8 weight percent and 2.2 weight percent. However, producers and importers may use the Predictive Model mechanism -- or an analogous mechanism in which alternative gasoline formulations are certified based on a vehicle test program -- to establish a maximum oxygen content limit as high as 2.7 weight percent. Except in the winter, gasoline formulations meeting the Predictive Model or vehicle testing criteria are allowed to have less oxygen than 1.8 weight percent, including zero oxygen. Alternative formulations with oxygen contents below 1.8 weight percent are not allowable during specified winter oxygen control periods. This was done because the 1990 amendments to the federal Clean Air Act required that the State Implementation Plans (SIP) for all CO nonattainment areas include a minimum oxygen requirement in the winter months when CO concentrations are the highest (FCAA §211 (m)), and California contained eight CO nonattainment areas (along with two unclassified areas). The wintertime oxygen requirements are part of the California SIP, along with the rest of the CaRFG regulations.

The ARB staff has estimated emission reductions from on-road vehicles of 17 percent of hydrocarbons, 11 percent of NOx, 11 percent of CO, and 40 percent of potency-weighted toxic emissions for gasoline that exactly complies with the averaging limits. Because actual gasolines are generally somewhat "cleaner" and because they provide unquantified emission benefits such as reducing combustion-chamber deposits, actual emission reductions are believed to be greater.

The Amendments

At an August 27, 1998 hearing, the Board considered proposed amendments that would:

1. Increase the "cap" limit for oxygen from 2.7 to 3.5 percent by weight.

2. Rescind in most areas the requirement for at least 1.8 percent oxygen, by weight, in gasoline used in the winter. Ultimately, the requirement would be retained only in the counties of Los Angeles, Orange, Riverside, and Ventura, in compliance with federal law,

and in Imperial County, where the state and federal air quality standards for CO continue to be violated. Also, it would be retained through January 31, 2000 in Fresno and Madera Counties, and the Lake Tahoe Air Basin, to ensure maintenance of the state standard for CO.

3. Make the following minor technical changes:

- Correct drafting errors in the existing provisions on averaging.
- For purposes of compliance with the March RVP phase-in period, make the application of the RVP limit to gasoline shipped from northern refineries to southern marine terminals uniform with its application to gasoline imported from out-of-state.

- Exempt gasoline used to fuel racing vehicles from the CaRFG standards.

After considering testimony at the August 27, 1998 hearing, the Board acted to adopt all of the proposed amendments except for the change in the cap limit for oxygen from 2.7 to 3.5 weight percent in Section 2262.5(b) (and a conforming change to the "California Procedures for Evaluating Alternative Specifications for Phase 2 Reformulated Gasoline Using the California Predictive Model," incorporated by reference in Section 2265(a)(2)). The hearing considering the amendment raising the oxygen content cap was continued to the ARB's December 10, 1998 meeting.

Comparable Federal Regulations

The 1990 amendments to the federal Clean Air Act (FCAA) require US Environmental Protection Agency (US EPA) to adopt regulations regarding reformulated gasoline (FCAA §211(k)). US EPA has adopted these regulations as 40 C.F.R. §80.40 to §80.82. In California, they apply in San Diego County, the greater Los Angeles area (Los Angeles, Orange and Ventura Counties, and parts of Riverside and San Bernardino Counties), and the greater Sacramento area (Sacramento County and parts of Yolo, Solano, Sutter, Placer, and El Dorado Counties).

The FCAA provides that the federal regulations must require no NOx increase, a minimum 2.0 percent by weight oxygen content (with certain exceptions), a maximum 1.0 percent by volume benzene content, and limits on heavy metals. The federal regulations must also specify performance standards for hydrocarbons in the high ozone period and toxic compounds year-round in two phases -- the first starting in 1995 and the second starting in 2000. The US EPA regulations identify a "complex model" that must now be used in complying with the requirements.

While the federal RFG standards apply in the federal RFG areas in California, the ARB has worked with US EPA and gasoline producers to avoid unnecessary duplication of the enforcement requirements. In 40 C.F.R. §80.81, US EPA has exempted California producers from many of the federal enforcement requirements from March 1, 1996 to January 1, 2000, as long as certain criteria are met.

EXHIBIT B

OXYGENATE INFORMATION SHEETS

Oxygenate Information Sheets

California and other areas throughout the United States use reformulated gasoline to help reduce emissions of criteria pollutants and achieve compliance with various air quality standards. Oxygenates are a critical gasoline blending component that enables refiners to produce gasoline that conforms to the reformulated specifications. Most oxygenates, except ethanol, are completely compatible with the distribution system and can be easily shipped through pipelines to various locations throughout the state. This fact sheet provides a quick reference on the various types currently being blended into reformulated gasoline (RFG), what California is using, a definition of oxygenates, the intended purposes of their use, and some of the major differences in characteristics that make certain types of oxygenates more desirable than others.

Types: Oxygenates are grouped into two different classes, ethers and alcohols. Currently, there are three different ethers in use throughout the United States. The most popular one is methyl tertiary butyl ether (MTBE), followed by ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME). Ethanol is the only alcohol currently in use as an oxygenate.

California: Refiners in California currently use MTBE (approximately 95,000 barrels per day) and some TAME (about 3,000 barrels per day) to meet most of their oxygenate needs. Only a small volume of ethanol is currently being used in California as an oxygenate due to a variety of factors, namely: lack of splash-blending equipment and inadequate segregated storage capacity throughout the distribution system and some less desirable blending characteristics (compared to other oxygenates). Approximately 85 percent of the MTBE used as oxygenates in California is imported from facilities located in the Middle East, Canada and the Gulf Coast of the United States. The remaining 15 percent is produced by California refineries from available feedstocks that are normally generated through the processing of crude oil. These refiners are unable to be completely self-sufficient in ether production because they lack the necessary volumes of feedstocks.

Definition: Oxygenates are a class of compounds that are blended with gasoline to increase the amount of oxygen contained in the fuel. Most petroleum blendstocks that are mixed together to create gasoline contain long chains of hydrocarbons consisting of hydrogen and carbon. It is the addition of oxygenates that provides the source of oxygen in RFG.

Purpose: Oxygenates are used to increase the oxygen content of gasoline so that the fuel will burn more completely in the engine, reducing tailpipe emissions of carbon monoxide. Many regions throughout the United States and especially California are in violation of federal carbon monoxide standards during the winter months and use oxygenated gasoline to reduce the number of violations and achieve compliance with

federal standards. Oxygenates are also used in reformulated gasoline year-round to dilute the volumes of other less desirable compounds , such as benzene, sulfur, aromatics and olefins. When the presence of these compounds is reduced to achieve compliance with the RFG regulations, octane is lost and must be replaced by mixing a high octane blendstock back into the gasoline. Oxygenates can and do serve this purpose.

Differences: Ethers exhibit many characteristics that are similar to gasoline and therefore do not pose any major challenge for the distribution infrastructure of pipelines, pumping stations, terminals, storage tanks, loading racks, delivery trucks, underground tanks and pumps at retail service stations.

Ethanol exhibits two characteristics that pose difficulties for distribution and compliance with certain gasoline specifications. First, ethanol has a great affinity for water, meaning ethanol will easily mix with any water encountered by ethanol in the distribution system, reducing the energy content of the ethanol and introducing problems with engines operating on gasoline containing contaminated ethanol. Because of this problem, ethanol is not blended with gasoline prior to shipment through the pipeline system, rather, ethanol is "splash-blended" with gasoline in the tanker truck prior to delivery to service stations. Ethers do not have an affinity for water (just like gasoline). Water that is normally found in small amounts throughout the distribution system does not mix with gasoline and can be drained from storage and automobile tanks because it separates from the gasoline and lies on the bottom of these tanks.

When ethanol is splash blended with gasoline, necessary precautions must be undertaken to ensure that the final blend of gasoline and ethanol will not violate the Reid vapor pressure (Rvp) standard, one of the fuel specifications regulated by state and federal regulatory agencies. Ethanol blended with gasoline tends to increase the Rvp of the finished gasoline greater than any of the ethers. As a consequence, gasoline shipped to terminals for splash-blending must contain an Rvp lower than normal (during the summer months) so that the final blended product does not exceed the Rvp standard. These batches of lower than normal Rvp gasoline are costlier to produce and require additional segregation from the other types of gasoline at the refinery. At the terminals, the ethanol used for splash-blending must also be stored separately and special equipment must be installed to allow for splash-blending.

Table 1

Characteristics of Oxygenates

Property	ETBE	Ethanol	MTBE	TAME	TBA
Fungibility in Gasoline Distribution System	High	Low	High	High	High
Energy Density - MBtu/gal (LHV)	96.9	76.0	93.5	100.6	94.1
Oxygen Content (wt.%)	15.7	34.8	18.2	15.7	21.6
Amount required to achieve 2.1 wt.% oxygen level in reformulated gasoline (volume percent)	13.4	6.0	11.5	13.4	9.7
Amount required to achieve 2.7 wt.% oxygen level in reformulated gasoline (volume percent)	17.2	7.8	14.8	17.2	12.5
Amount required to achieve 3.5 wt.% oxygen level in reformulated gasoline (volume percent)	22.3	10.0	19.2	22.3	16.2
Solubility in Water (wt.%)	1.20	Infinite	4.30	1.15	Infinite
Blending Rvp (psi)	4.0	18.0	8.0	2.5	9
Octane Blending (R+M)/2	112	115	110	105	100
Vapor Pressure Neat Rvp (100 Degrees F.)	4.40	2.30	7.80	1.50	1.70
Boiling Point (Degrees F.)	164	172	131	187	181
Density @ 60 degrees F. (lb/gal)	6.25	6.61	6.19	6.41	6.60
Latent Heat of Vaporization - MBtu/gal (@ N.B.P.)	0.83	2.39	0.86	0.90	1.55
Feedstocks	Isobutylene, Ethanol	Sugar Fermentation	Isobutylene, Methanol	Isoamylene, Methanol	Isobutylene, Water
U.S. EPA Additive Registration Approval	Yes	Yes	Yes	Yes	Yes

Notes:
MBtus/gal - Energy content in thousands of British thermal units per gallon.
LHV - Lower heating value.
wt.% - weight percent
Rvp - Reid vapor pressure.
psi - pounds per square inch
(R+M/2) - An arithmetic average of the Research and Motor octane values.
Octane - Measure of the antiknock performance, the higher the number, the greater resistance to knocking.
N.B.P. - normal boiling point

EXHIBIT C

FEDERAL REGISTER DOCUMENT

Change in Minimum Oxygen Content Requirement for Reformulated Gasoline

Change in Minimum Oxygen Content Requirement for Reformulated Gasoline [1]

[Federal Register: July 9, 1998 (Volume 63, Number 131)]
[Notices]
[Page 37112-37114]
From the Federal Register Online via GPO Access [wais.access.gpo.gov]
[DOCID:fr09jy98-75]

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ENVIRONMENTAL PROTECTION AGENCY

[FRL-6121-8]

Change in Minimum Oxygen Content Requirement for Reformulated Gasoline

AGENCY: Environmental Protection Agency.

ACTION: Notice.

SUMMARY: EPA's reformulated gasoline (RFG) program contains various standards for RFG, including an oxygen content standard. When the RFG program was implemented, the per-gallon minimum standard applicable to RFG in all covered areas was 1.5% by weight. In 1997, pursuant to the RFG regulations, EPA increased this standard by 0.1% to 1.6% by weight for several of the RFG covered areas (and for certain refineries, importers and blenders) because these areas failed a series of compliance surveys for oxygen content in 1996. Certain covered areas have failed the oxygen compliance survey series for 1997, and EPA is increasing the per-gallon minimum standard applicable to these areas by 0.1%. Since the previous increases remain in effect, the per-gallon minimum oxygen requirement in all but one of these areas failing in 1997 will increase to 1.7% by weight. This notice announces the increased standard, and describes the covered areas and parties that are subject to the increased standard. The increased standard will help ensure that all covered areas receive the full benefit of the oxygen content requirement in the RFG program.

FOR FURTHER INFORMATION CONTACT: Stuart Romanow, Fuels and Energy Division, Office of Mobile Sources, Environmental Protection Agency, Washington D.C. (6406J) 202-564-9296.

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[1] Note a copy of this document may also be obtained at the following web page address: http://www.epa.gov/fedrgstr/EPA-AIR/1998/July/Day-09/a18080.htm.

SUPPLEMENTARY INFORMATION:

I. Regulatory Entities

Regulatory categories and entities potentially affected by this action include:

Category	Examples of affected entities
Industry	Refiners, importers, oxygenate blenders of reformulated gasoline.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. This table lists the types of entities that EPA is now aware could be potentially affected by this action. Other types of entities not listed in the table could also be affected. To determine whether your entity is affected by this action, you should carefully examine the existing provisions at 40 CFR 80.41. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding FOR FURTHER INFORMATION CONTACT section.

II. Background

Section 211(k) of the Clean Air Act requires that EPA establish standards for reformulated gasoline (RFG) to be used in specified ozone nonattainment areas (covered areas). The RFG requirements contain performance standards for reductions of emissions from motor vehicles of ozone forming volatile organic compounds and toxic pollutants.

Standards for RFG are contained in 40 CFR 80.41. Refiners and other parties subject to the standards can choose to comply on either a per gallon basis or to comply on average. The standards for compliance on average (``averaged standards'') are numerically more stringent than the per gallon standards. The averaged standards for RFG are contained in Sec. 80.41(b). These averaged standards include a per-gallon minimum requirement of 1.5 weight percent oxygen. This 1.5% per-gallon minimum oxygen requirement initially applied to all refineries, importers and blenders of RFG who elected to comply with the averaged standard for oxygen. However, as a result of oxygen survey series failures in 1996, EPA required that certain refineries, importers and blenders comply with a 1.6% minimum, beginning on September 29, 1997.[2] (The survey process and the consequences of oxygen survey series failures are described below.) The per-gallon minimum requirement is in addition to the requirement for 2.1 weight percent oxygen, on average. The average standard for oxygen must be met by a

[2] See ``Change in Minimum Oxygen Requirement for Reformulated Gasoline'' 62 FR 41047 (July 31, 1997).

refiner or oxygenate blender for all of the RFG it produced at a refinery or blending facility, or for RFG imported by an importer, but these parties are not required to meet this standard for the RFG supplied to each covered area separately.

Any refiner, importer or oxygenate blender has the option of meeting the RFG standards on average or per gallon. If a party is subject to the averaged standards, then the requirement to conduct surveys, as specified in Sec. 80.68, must be satisfied. In these surveys, RFG samples are collected at retail gasoline stations within covered areas and analyzed to determine if the RFG supplied to each covered area meets certain survey pass/fail criteria specified in Sec. 80.68. An oxygen survey series failure occurs in a covered area if the annual average oxygen content for all of the samples is less than 2.00 weight percent. The purpose of the surveys and the tightened standards which result if a survey is failed is to ensure that averaging over a refiner's entire production as compared to separate averaging for each covered area does not lead to the reduced quality of RFG in any covered area.

Since the implementation of the RFG program in 1995, these surveys have been conducted by the RFG Survey Association, a not-for-profit association of refiners, importers and blenders, using an EPA-approved survey design plan as required in the regulations. By letter dated January 30, 1998, the RFG Survey Association reported to EPA the results of its surveys for 1997, indicating that several survey areas failed to meet the annual average requirements of 2.00% oxygen by weight.[3] After reviewing the data EPA determined that 7 areas did fail the survey series for oxygen content.[4]

The following covered areas failed the oxygen survey series:

1. Baltimore, MD area [Sec. 80.70(g)].
2. Houston-Galveston-Brazoria, TX area [Sec. 80.70(h)].
3. The entire State of Rhode Island [Sec. 80.70(j)(12)].
4. The Dallas-Fort Worth, TX area comprised of [Sec. 80.70(j)(13)]:

Collin County
Dallas County
Denton County
Tarrant County

5. Norfolk-Virginia Beach-Newport News (Hampton Roads), VA area comprised of [Sec. 80.70(j)(14)]:

Chesapeake

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[3] Letter dated January 30, 1998 from Frank C. Lenski, President, RFG Survey Association, to Charles Freed, Director, Fuels and Energy Division, EPA.
[4] Letter dated March 4, 1998 from Charles Freed, EPA, to Frank Lenski, RFG Survey Association. Also see Memorandum dated March 20, 1998 from Stuart Romanow, Mechanical Engineer, Fuels and Energy Division to Charles Freed.

Hampton
James City County
Newport News
Norfolk
Poquoson
Portsmouth
Suffolk
Virginia Beach
Williamsburg
York County

6. Richmond, VA area comprised of [Sec. 80.70(j)(14)]:

Charles City County
Chesterfield County
Colonial Heights
Hanover County
Henrico County
Hopewell
Richmond

7. Washington D.C. area comprised of [Sec. 80.70(j)(2), (j)(6), (j)(14)]:

The District of Columbia
Calvert County, MD
Charles County, MD
Frederick County, MD
Montgomery County, MD
Prince Georges County, MD
Alexandria, VA
Arlington County, VA
Fairfax, VA
Fairfax County, VA
Falls Church, VA
Loudoun County, VA
Manassas, VA
Manassas Park, VA
Prince William County, VA
Stafford County, VA

The boundaries of the covered areas are described in detail in Sec. 80.70.

Under Sec. 80.41(o), when a covered area fails an oxygen content survey series, the minimum oxygen content requirement for that covered area is made more stringent by

increasing the per gallon minimum oxygen content standard for affected RFG subject to the averaging standard by 0.1%. This more stringent requirement applies beginning the year following the year of the failure. A more stringent requirement remains in effect for a covered area unless the area passes all oxygen content survey series in two consecutive years. Therefore, with the exception of the entire State of Rhode Island, the minimum per gallon oxygen requirement for the areas listed above is increased from 1.6% to 1.7% by weight. The minimum per gallon oxygen requirement for the entire State of Rhode Island is increased from 1.5% to 1.6% by weight. In addition, the minimum per gallon oxygen requirement for the Philadelphia-Wilmington-Trenton area and the Atlantic City, NJ area (Atlantic County and Cape May County), which failed oxygen content survey series in 1996, remains at 1.6% by weight.

The criteria identifying the refineries, importers and oxygenate blenders subject to adjusted standards are stated in Sec. 80.41(q). In general, adjusted standards apply to RFG that is subject to an averaging standard ("averaged RFG") that is produced at a refinery or oxygenate blending facility if any averaged RFG from that refinery or facility supplied a failed covered area during 1996, or supplies the covered area during any year that the more stringent standards are in effect. The regulation provides for an exception based on certain volume limits [see 40 CFR Sec. 80.41(q)(1)(iii)].

Thus, if a refiner has elected for a refinery to be subject to the average oxygen standard, and if even a small portion of the RFG produced at the refinery is used in an area subject to an oxygen ratchet, the entire volume of RFG produced at the refinery is subject to the more stringent oxygen standard regardless of which area receives the RFG. This result is true regardless of whether the refinery's gasoline was supplied to the city in question during 1997 or during a year when the more stringent oxygen standard applies.

Under Sec. 80.41(q)(2), the applicability of adjusted standards to imported averaged RFG is specified by the Petroleum Administration for Defense District (PADD) in which the covered area is located and the PADD where the gasoline is imported. The covered areas that had oxygen survey series failures are located in PADDs I and III. Therefore, all RFG imported at facilities located in PADDs I, II, III or IV is subject to the adjusted oxygen standard. The states included in each PADD are identified in Sec. 80.41(r). In addition, if any RFG imported into any other PADD supplies any of the covered areas with oxygen survey failures, the adjusted standard applies to that RFG, as well.

Under Sec. 80.41(q)(3), any gasoline that is transported in a fungible manner by a pipeline, barge or vessel is considered to have supplied each covered area that is supplied with any gasoline by that pipeline, barge or vessel shipment unless the refiner or importer is able to establish that the gasoline it produced or imported was supplied only to a smaller number of covered areas.

Consider, for example, gasoline transported on the Colonial Pipeline, which supplies RFG to several cities that failed the oxygen survey in 1997. If a refinery's RFG was transported by the Colonial Pipeline any time during 1997, or any time during any year when the more

stringent oxygen standard applies, the more stringent oxygen standard applies to all RFG produced at the refinery regardless of the market. In addition, there is a presumption that, due to fungible mixing, each refinery's RFG that is transported by the Colonial Pipeline is in part supplied to each city supplied by the Colonial Pipeline. This presumption is rebuttable, but the rebuttal normally would require a refiner to have transported its RFG in a non-fungible manner. Thus, the more stringent standard applies to a refinery whose gasoline is transported on the Colonial Pipeline regardless of whether the refiner takes delivery of RFG in the specific cities that failed the oxygen survey.

The adjusted oxygen standard applies to all averaged RFG produced by a refinery or imported by an importer identified in Sec. 80.41(q). In accordance with Sec. 80.41(p), the effective date of this change is October 7, 1998.

Thus, under Sec. 80.41(p) the more stringent oxygen standard applies at all points of the distribution system beginning on October 7, 1998, including terminals supplying the affected covered areas and retail outlets in the covered areas. However, EPA believes it may be difficult for all regulated parties to transition to the new oxygen standard by October 7, 1998. As a result, EPA intends to enforce the new oxygen standard in a manner that gives parties additional time. Refiners, importers, and oxygenate blenders will be required to meet the new oxygen standard beginning October 7, 1998. In the case of parties other than refiners, importers, oxygenate blenders, retailers and wholesale purchaser-consumers, (e.g., pipelines and terminals supplying gasoline to affected covered areas) EPA will enforce the new oxygen standard beginning December 7, 1998.[5] In the case of retail outlets and wholesale purchaser-consumer facilities located in the affected covered areas EPA will enforce the new oxygen standard beginning January 5, 1999. EPA has initiated a rulemaking to revise Sec. 80.41(p) to reflect the need for additional downstream transition time when a standard is changed.

Dated: June 9, 1998.
Richard D. Wilson,
Acting Assistant Administrator for Air and Radiation.

Sylvia K. Lowrance,
Acting Assistant Administrator for Enforcement and Compliance Assurance.
[FR Doc. 98-18080 Filed 7-8-98; 8:45 am]
BILLING CODE 6560-50-P

[5] This supersedes the timing of the enforcement of the downstream oxygen standards discussed in “RFG/Anti-Dumping Questions and Answers, November 12, 1996”'. See question and answer under topic ``SURVEYS 11/12/96''.

EXHIBIT D

BILL SUMMARY AND STATUS FOR THE 105TH CONGRESS

H.R. 630

BILL SUMMARY AND STATUS FOR THE 105TH CONGRESS

H.R. 630

SPONSOR: Rep Bilbray (Introduced 02/06/97)

TITLE:

A bill to amend the Clean Air Act to permit the exclusive application of California State regulations regarding reformulated gas in certain areas within the State.

STATUS: Floor Actions

NONE

STATUS: Detailed Legislative Status

HOUSE ACTIONS

Feb 6, 97: Referred to the House Committee on Commerce
Feb 14, 97: Referred to the Subcommittee on Health and Environment
Apr 22, 98: Subcommittee Hearings held

STATUS: Congressional Record Page References

02/10/97 Introductory Remarks on Measure (CR E196)

COMMITTEE(S):

Committee of Referral: House Commerce

Subcommittee: Hsc Health and the Environment

AMENDMENTS:

None

COSPONSORS:

Rep Lewis, Jerry - 02/06/97
Rep Calvert - 02/06/97
Rep Filner - 02/06/97
Rep Herger - 02/06/97
Rep Packard - 02/06/97
Rep Torres - 02/06/97
Rep Hunter - 02/06/97
Rep Cunningham - 02/06/97
Rep Rohrabacher - 02/06/97
Rep Dooley - 02/06/97

Rep Cox - 02/06/97
Rep Royce - 02/27/97
Rep Martinez - 03/03/97
Rep Thomas - 03/19/97
Rep Tauscher - 04/08/97
Rep Rogan - 04/15/97
Rep Millender-McDonald - 04/24/97
Rep Farr - 05/07/97
Rep Miller, G. - 05/07/97
Rep Eshoo - 05/13/97
Rep Dellums - 05/21/97
Rep Dixon - 06/03/97
Rep Lofgren - 06/03/97
Rep Stark - 06/17/97
Rep Waters - 06/20/97
Rep Campbell, Tom - 06/26/97
Rep Lantos - 07/09/97
Rep Doolittle - 07/10/97
Rep Brown, G. - 02/12/98
Rep Condit - 02/12/97
Rep Radanovich - 03/03/97
Rep Bono, Sonny - 03/19/97
Rep Fazio - 03/19/97
Rep Gallegly - 04/15/97
Rep Harman - 04/23/97
Rep Riggs - 05/07/97
Rep Horn - 05/07/97
Rep Roybal-Allard - 05/08/97
Rep Dreier - 05/16/97
Rep Capps, Walter - 06/03/97
Rep Pombo - 06/03/97
Rep Kim - 06/12/97
Rep McKeon - 06/20/97
Rep Sherman - 06/20/97
Rep Matsui - 07/09/97
Rep Pelosi - 07/09/97
Rep Woolsey - 07/14/97
Rep Becerra - 06/17/98

SUMMARY:

(AS INTRODUCED)

Amends the Clean Air Act to allow reformulated gasoline rules of States for which a certain waiver is in effect (permitting them to enforce State motor vehicle emissions standards) to apply in an ozone nonattainment area in lieu of Environmental Protection Agency-promulgated requirements if the State rules will achieve reductions in the aggregate mass of emissions of toxic air pollutants and the aggregate mass of emissions of ozone-forming compounds at least as great as would result from application of the Federal requirements.