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Ethanol Demand in United States Gasoline Production

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G. R. Hadder

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Energy Division

ETHANOL DEMAND IN UNITED STATES GASOLINE PRODUCTION

G. R. Hadder

Center for Transportation Analysis
Oak Ridge National Laboratory
Oak Ridge, Tennessee

November 24, 1998

Prepared by the
OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37831
managed by
LOCKHEED MARTIN ENERGY RESEARCH CORP.
for the
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Annualized demand volumes are derived by weighting the seasonal demand volumes, and expressing as an annual demand which is plotted in the figures. Annualized demand is the best estimate of actual demand for the entire year, taking into account seasonal effects. For example, if the summer season is 5.5 months, then:

$$\text{Annualized demand} = 5.5/12 * (\text{Summer demand, year-based}) + 6.5/12 * (\text{Winter demand, year-based}).$$

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ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BGY	Billion gallons per year
Btu	British thermal unit
CAAA	Clean Air Act Amendments of 1990
CARB	California Air Resources Board
CEC	California Energy Commission
CCR	California Code of Regulations
CG	Conventional gasoline
CO	Carbon monoxide
DCF	Discounted cash flow
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ETBE	Ethyl tertiary butyl ether
E200	The cumulative volume percent evaporated at 200°F in ASTM test D86-87: Distillation of Petroleum Products
E300	The cumulative volume percent evaporated at 300°F in ASTM test D86-87: Distillation of Petroleum Products
F	Fahrenheit
FCC	Fluid catalytic cracking
FOE	Fuel oil equivalent
gm	gram

LSG	Low sulfur gasoline
M	Motor octane number
max	Maximum
MBD	Thousand barrels per day
MBPD	Thousand barrels per day
MBSD	Thousand barrels per stream day
mg/mi	Milligrams per mile
MM	Million
MST/D	Thousand short tons per day
ST/CD	Short tons per calendar day
MTBE	Methyl tertiary butyl ether
NIPER	National Institute for Petroleum and Energy Research
NO _x	Oxides of nitrogen
NPC	National Petroleum Council
NPRA	National Petroleum Refiners Association
ORNL	Oak Ridge National Laboratory
PADD	Petroleum Administration for Defense District
PM ₁₀	Particulate matter under 10 microns
ppm	Part per million
psi	Pounds per square inch
R	Research octane number
RFG	Reformulated gasoline
RVP	Reid vapor pressure
RYM	Refinery Yield Model

SOx	Sulfur oxides
Sum	Summer
TAP	Toxic air pollutant
T50	The temperature at which 50 percent of a test volume of fuel is evaporated in ASTM test D86-87: Distillation of Petroleum Products
T90	The temperature at which 90 percent of a test volume of fuel is evaporated in ASTM test D86-87: Distillation of Petroleum Products
VOC	Volatile organic compound
vol	Volume
Win	Winter
wppm	Parts per million, by weight (same as ppm in this report)
wt	Weight

ABSTRACT

The Oak Ridge National Laboratory (ORNL) Refinery Yield Model (RYM) has been used to estimate the demand for ethanol in U.S. gasoline production in year 2010. Study cases examine ethanol demand with variations in world oil price, cost of competing oxygenate, ethanol value, and gasoline specifications. For combined-regions outside California, summer ethanol demand is dominated by conventional gasoline (CG) because the premised share of reformulated gasoline (RFG) production is relatively low and because CG offers greater flexibility for blending high vapor pressure components like ethanol. Vapor pressure advantages disappear for winter CG, but total ethanol used in winter RFG remains low because of the low RFG production share. In California, relatively less ethanol is used in CG because the RFG production share is very high. During the winter in California, there is a significant increase in use of ethanol in RFG, as ethanol displaces lower-vapor-pressure ethers. Estimated U.S. ethanol demand is a function of the refiner value of ethanol. For example, ethanol demand for reference conditions in year 2010 is 2 billion gallons per year (BGY) at a refiner value of \$1.00 per gallon (1996 dollars), and 9 BGY at a refiner value of \$0.60 per gallon. Ethanol demand could be increased with higher oil prices, or by changes in gasoline specifications for oxygen content, sulfur content, emissions of volatile organic compounds (VOCs), and octane numbers.

ETHANOL DEMAND IN UNITED STATES GASOLINE PRODUCTION

EXECUTIVE SUMMARY

In 1996, the U.S. Department of Energy (DOE) Office of Fuels Development studied pathways for the corn ethanol industry to evolve into a cellulosic ethanol industry under two predetermined ethanol market share scenarios. Instead of using market share assumptions, a new approach for 1997-1998 starts from "square one" in DOE's Analysis of Market Potential and Benefits of Cellulosic Ethanol. The analysis includes assessments of demand for ethanol blended to gasoline, demand for neat ethanol, and ethanol's competition from other alternative fuels, gasolines, and oxygenates. A key task is "Estimation of Ethanol Demand in Gasoline Production," which is designed to analyze competition from gasoline and oxygenates and to identify opportunities for ethanol use in U.S. gasoline production. The ORNL-RYM has been used to accomplish this task.

ORNL-RYM is a linear program with extensive representations of refining processes, refined products, crude oils, and capacity investment. ORNL-RYM incorporates gasoline blending to satisfy formula and emissions standards mandated by the Clean Air Act Amendments of 1990 (CAAA) and described by the Environmental Protection Agency (EPA) Complex Model, which predicts pollutant emissions in terms of gasoline properties.

Data for the study are based on information published by DOE, the U.S. Energy Information Administration (EIA), the National Petroleum Council (NPC), National Petroleum Refiners Association (NPRA), the California Air Resources Board (CARB), and industry journals. The study designs are shown in Tables S-1 and S-2. Study cases for year 2010 investigate regional refiner/blender demand for ethanol for reference case conditions and for higher ethanol demand conditions, with variations in world oil price, cost of competing oxygenate, ethanol value, and gasoline specifications.

Table S-1. Phase 1 studies of demand for ethanol in U.S. gasoline production and finishing in year 2010								
Factor	Reference conditions				Higher ethanol demand case			
PADD	II	II	III	III	II	II	III	III
Season	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
RFG share (percent)	Current (12)	Current (13)	Current (18)	Current (18)	Current (12)	Current (13)	Current (18)	Current (18)
World oil price (per barrel)	Reference (\$24.77)	Reference (\$24.77)	Reference (\$24.77)	Reference (\$24.77)	High (\$34.08)	High (\$34.08)	High (\$34.08)	High (\$34.08)
MTBE cost	Function of reference case outlook	Function of reference case outlook	Function of reference case outlook	Function of reference case outlook	Function of high price case outlook	Function of high price case outlook	Function of high price case outlook	Function of high price case outlook
Ethanol value	Vary	Vary	Vary	Vary	Vary	Vary	Vary	Var

Table S-2. Phase 2 studies of demand for ethanol in U.S. gasoline production and finishing												
Factor	Reference conditions											
PADD	I	I	II	II	II	II	II	II	III	III	VC	VC
Season	Sum	Win	Sum	Win	Sum	Sum	Sum	Sum	Sum	Sum	Sum	Win
Ethanol in gasoline, percent	≤10	≤10	17	17	≤10	≤10	≤10	≤10	≤10	≤10	≤10	≤10
LSG share, percent	0	0	0	0	100	0	0	0	0	0	0	0
VOC Waiver						Yes						
Toxicity correction							Yes					
Octane Increase								Yes				
Ratio-constrained Model									Yes			
Parametric variation of ethanol value									No			
Latest outlook for energy markets										Yes		

There are three key premises for the study. First, it is assumed that gasoline blending is optimized with minimum giveaway of gasoline quality. Modeled refineries can produce subgrade gasolines for shipment to blenders who add optimal volumes of ethanol to produce finished gasoline. Second, ethanol handling and logistics costs in refining/blending are assumed to be 10 cents per gallon. Third, it is assumed that consumers are indifferent to ethanol blends, neither seeking nor avoiding these gasolines.

ORNL-RYM analysis of regions outside California shows that future summer ethanol demand is dominated by CG because (1) limits on emissions of VOCs make summer RFG difficult to produce with high vapor pressure oxygenates like ethanol, and (2) ethanol's attractiveness in CG is enhanced by the 1 pounds per square inch (psi) Reid vapor pressure (RVP) waiver for 10 percent ethanol blends. With a lower production share for RFG, as in Petroleum Administration for Defense District (PADD) II (U.S. Midwest) and PADD III (U.S. Gulf Coast), there is greater demand for ethanol because of the relatively greater volume of CG. While RVP advantages disappear for winter CG, total ethanol used in winter RFG is limited by the RFG share.

For premised conditions in California (PADD VC), future summer ethanol demand is dominated by ethyl tertiary butyl ether (ETBE) and ethanol blended to RFG. Relatively less ethanol is used in CG because the RFG production share is very high. During the winter, there is a significant increase in use of ethanol in RFG, as ethanol displaces lower-RVP ETBE.

Based on crude distillation capacity, 90 percent of U.S. refinery capacity is included in the ethanol demand study for reference conditions. For higher ethanol demand conditions, 69 percent of refinery capacity is covered by study cases. The regional annualized ethanol demand estimates have been scaled to provide estimates of demand for ethanol in the total U.S. gasoline production system, as shown in

Figure S-1. Estimated U.S. ethanol demand is a function of the refiner value of ethanol, which is the highest price (after credit for subsidies) that an ethanol producer can command at the refinery/blender gate, as determined by ethanol's value as an ether feedstock or by the refining values of the gasoline blendstocks it displaces. Ethanol demand for reference conditions in year 2010 is 2 BGY at a refiner value of \$1.00 per gallon (1996 dollars), and 9 BGY at a refiner value of \$0.60 per gallon. For higher ethanol demand conditions, ethanol demand is 7 BGY at a refiner value of \$1.00 per gallon, and 11 BGY at a refiner value of \$0.60 per gallon of ethanol. This study has not estimated the potential demand for ethanol in imported gasolines, which account for about 4 percent of gasoline supplied to U.S. consumers.

In Figure S-2, the U.S. demand for ethanol in the total U.S. gasoline production system under reference conditions has been disaggregated into demand by gasoline type. Figure S-2 shows that the demand for ethanol is dominated by CG over most of the range of refiner values for ethanol.

Multiyear forecasts of ethanol supply and demand are required to examine tax incentive schedules to help initiate a commercial cellulosic ethanol industry. For the component of demand due to ethanol blending in gasoline, the refinery model's ethanol demand curve for reference conditions in year 2010 has been extrapolated to demand curves for five-year intervals between years 2000 and 2025, as shown in Figure S-3.

The original study design assumed that full opt-in for RFG would be the appropriate premise for higher ethanol demand conditions due to the mandated minimum oxygen levels for RFG. However, exploratory runs showed that annualized ethanol demand was lower with a higher RFG share of total gasoline production. Therefore, for higher ethanol demand conditions, the study premises were changed to a low RFG production share (current share). RFG's negative effect on ethanol demand is a most important finding.

It is assumed that refiners will use prohibitively high hurdle rates when considering investment in new technologies, because the advertised capabilities of new technologies are not always realized. Therefore, investment is restricted to proven technologies in the study cases. A sensitivity case with investment opened to additional process technology shows that expanded investment options have negligible effects on ethanol demand.

For premised conditions, requirements for high quality gasoline blendstocks can fall as ethanol is added to gasoline, with a decrease in utilization of process units which produce these blendstocks. Some capacity can become available for distillate processing, and investment in distillate processing can decrease. Sensitivity cases for more stringent gasoline specifications, as in low sulfur gasoline (LSG), show that higher sulfur gasoline blendstocks will be upgraded or displaced by ethanol, while high quality low sulfur blendstocks are retained or increased.

Changes in gasoline specifications could result in higher ethanol demand. In sensitivity cases, ethanol demand has been estimated for gasoline specification changes for oxygen content, sulfur content, VOC emissions, toxic air pollutant (TAP) emissions, and octane number. Sensitivity cases have also explored the effects of a different version of ORNL-RYM and different premise data.

While the maximum allowable oxygen content for gasoline is currently 3.5 weight (wt) percent for ethanol blends, it has been reported that modern vehicles can perform adequately with oxygen levels of

Fig. S-1. Ethanol demand range for U.S. gasoline production and finishing in year 2010

Fig. S-2. Ethanol demand breakdown for U.S. gasoline production and finishing in year 2010 - reference conditions

Fig. S-3. Ethanol demand for U.S. gasoline production and finishing in years 2000 to 2025 - reference conditions

up to 6 wt percent. To evaluate its sensitivity to the oxygen specification for gasoline, ethanol demand in PADD II has been estimated in summer and winter cases with a maximum allowable oxygen content of 6 wt percent. With the revised oxygen specification, ethanol demand increases by as much as 16 percent.

EPA believes that reduction of sulfur in gasoline may be required to enable use of advanced vehicle pollution control technologies. Summer ethanol demand has been estimated for PADD II, with production of 100 percent LSG at 100 parts per million sulfur. ORNL-RYM shows that a requirement for LSG gasoline substantially increases the demand for ethanol over a significant range of refiner values for ethanol. The ethanol demand increase is due, in part, to benefits of ethanol in sulfur reduction through dilution. In conventional hydrocarbon processing, there is a loss of octane in the reduction of sulfur (through saturation of olefins), and the ethanol demand increase is also related to octane recovery. The LSG program will be less costly if less than 100 percent of gasoline is LSG, and ethanol demand will be less with a smaller LSG program. Ethanol demand could be higher with a lower sulfur specification for LSG.

Limitations on VOC emissions make summer RFG difficult to produce with high vapor pressure oxygenates like ethanol, and proponents of ethanol use in RFG have sought relief from the current VOC specification. In a sensitivity case study, the premised VOC specification for ethanol-based RFG allows a 5 percent increase in VOC emissions. This waiver decreases the VOC advantage of MTBE-based RFG. There is an ethanol demand increase with the VOC waiver in PADD II. However, this increase is muted by the fact that only 11 percent of gasoline produced in PADD II gasoline is RFG. The effect of the waiver could be a significant increase in ethanol demand with an RFG production share of 30 percent--the national average.

The EPA Complex Model for emissions of pollutants does not account for TAP emissions associated with evaporative and exhaust emissions of MTBE. If TAP due to MTBE were accounted for, ethanol could have an additional advantage in gasoline blending. In a sensitivity case, the TAP specification for ethanol-containing RFG has been increased by the benzene-equivalent toxicity due to MTBE, which is not accounted for in the EPA Complex Model. However, the TAP correction has virtually no effect on ethanol demand in PADD II.

The likelihood of an increase in octane specification is uncertain, but nonetheless plausible. Ethanol is a very significant source of blending octane number. There is a correspondingly significant increase in ethanol demand when the octane specification for gasoline is increased by 1 number.

Overoptimization can occur as a result of ORNL-RYM's use of a modeling concept in which refinery streams with identical distillation cut points are kept separate through different refining processes. This modeling concept allows variations in key properties (e.g., sulfur content of gasoline) to be represented by linear combinations of streams with identical distillation cut points. Ratio constraints on refinery streams can be used to avoid unrealistic separation of streams with identical distillation cut points. A sensitivity case has examined the effect of a Ratio-constrained model on ethanol demand estimation for PADD III summer gasoline production. This comparison suggests that Ratio-free modeling (the basis for all other study cases) is a conservative approach for ethanol demand estimation. With ratio constraints, the value of hydrocarbons increases significantly, which favors the blending of ethanol. For a given demand level, the value of ethanol for the Ratio-constrained model case is 6 percent higher than the value in the original demand curve.

Key data for the ethanol demand studies are based on EIA outlooks for energy markets. From year to year, there can be significant changes in the outlook for oil prices and the supply of refined products. To evaluate the impact of changes in the outlook, a sensitivity case for ethanol demand in PADD III summer gasoline production has been examined using data from an outlook for a different year. Results suggest that ethanol demand is essentially the same with data from either outlook.

The study has two general conclusions. First, future demand for ethanol in gasoline production could be substantial as the refiner/blender value of ethanol decreases relative to the value of gasoline. Second, changes in gasoline specifications could further increase ethanol demand.

ETHANOL DEMAND IN UNITED STATES GASOLINE PRODUCTION

1. INTRODUCTION

In 1996, the U.S. DOE Office of Fuels Development studied pathways for the corn ethanol industry to evolve into a cellulosic ethanol industry under two predetermined ethanol market share scenarios. Instead of using market share assumptions, a new study approach for 1997-1998 starts from "square one" in DOE's Analysis of Market Potential and Benefits of Cellulosic Ethanol. The analysis includes assessments of demand for ethanol blended to gasoline, demand for neat ethanol, and ethanol's competition from other alternative fuels, gasolines, and oxygenates such as MTBE.

A key task is "Estimation of Ethanol Demand in Gasoline Production," which is designed to analyze competition from gasoline and oxygenates and to identify opportunities for ethanol use in U.S. gasoline production (Hadder 1997). The ORNL-RYM has been used to accomplish this task.

2. THE ORNL-RYM

ORNL-RYM is an enhanced personal computer version of the RYM of the Refinery Evaluation Modeling System (DOE 1984a; DOE 1984b; Tallett and Dunbar 1988; Tallett et al. 1992). ORNL-RYM is a linear program that includes 50 refining processes, which can be used to produce 40 different products from more than 100 crude oils. An investment module provides for the addition of processing capacity.

ORNL-RYM tracks octane, RVP, oxygen content, sulfur, benzene, aromatics, total olefins, distillation points, and pollutant emissions on all gasoline component streams. In separate data tables in ORNL-RYM, gasoline blending components are identified; blending values are assigned to these components; and blending targets are set. Properties for distillates and jet fuels are handled in a similar fashion.

ORNL-RYM can represent various regional refining configurations. It is important to recognize that refineries within a region can vary widely in technical capability, and that refineries are subject to temporal variations in complex operations. A regional refining outcome (such as refining cost change due to ethanol blending) spans a range, and this range has uncertainty. The model assumes that all refineries within a large region are interconnected, which tends to overoptimize regional refinery capability. Overoptimization can also occur as a result of ORNL-RYM's use of a modeling concept in which refinery streams with identical distillation cut points are kept separate through different refining processes. This modeling concept allows variations in key properties (e.g., sulfur content in gasoline) to be represented by linear combinations of streams with identical distillation cut points.

3. THE ORNL-RYM REPRESENTATION OF CLEANER GASOLINES

3.1 FORMULA AND EMISSIONS STANDARDS

ORNL-RYM represents blending to satisfy both formula and emissions standards for gasolines. Federal standards are mandated by the CAAA. The CAAA include programs for oxygenated gasoline and for RFGs. The oxygenated gasoline program requires that gasoline with a minimum oxygen content of 2.7 wt percent be sold during winter months in about 40 cities not in compliance with carbon monoxide (CO) standards. RFGs are required in nine areas with extreme or severe ozone pollution problems. CO nonattainment areas and RFG program areas are listed in Appendix A. The formula and emissions performance standards for RFGs produced after 1999 are shown in Table 1 (EPA 1994).

Table 1. Formula and emissions performance standards for the federal RFG program after 1999	
Standard	Phase II Environmental Protection Agency final rule standards (Beginning January 1, 2000)
Oxygen content	2 wt percent minimum
Benzene content	1 vol percent maximum
Additives	No additives with heavy metals
Volatile Organic Compounds (VOCs include all oxygenated and non-oxygenated hydrocarbons except methane and ethane)	Must be reduced during summer by 25.9 percent on a per-gallon basis or by 27.4 percent on an averaged basis. ^a Greater reduction is required in southern states.
Toxic Air Pollutants (TAPs consist of benzene, 1,3 butadiene, formaldehyde, acetaldehyde, and polycyclic organic matter)	Must be reduced year-round by 20 percent on a per-gallon basis or by 21.5 percent on an averaged basis.
Nitrogen Oxides (NOx)	Must be reduced during summer by 5.5 percent on a per-gallon basis or by 6.8 percent on an averaged basis. If summer averaging is used, then there must be at least a 3 percent reduction on a per-gallon basis. Must not increase during winter on a per-gallon basis and must be reduced by 1.5 percent on an averaged basis.
^a For the per-gallon standard, every batch of RFG produced at the refinery must meet the same emissions performance requirements. For the averaged standard, different batches may vary within limits, as long as the refinery's total RFG output satisfies the specified average emissions performance requirement.	

Emissions modeling provides a means for predicting the emissions performance of a gasoline, given other properties of the gasoline. The Complex Model of the EPA is a set of non-linear equations that predicts emissions of VOCs, TAPs, and oxides of nitrogen (NO_x) in terms of gasoline properties including RVP, E200, E300, benzene, oxygen, sulfur, aromatics, and olefins contents (Korotney 1993). The Complex Model must be used after March 1, 1997, to certify the emissions performance of all gasolines except California RFG, which is subject to stringent recipe or Predictive Model specifications (see Section 4.1).

The nine areas in the extreme and severe ozone nonattainment categories comprise about 30 percent of the nation's gasoline market. In fact, all gasolines will be affected by the CAAA. Besides requiring RFG in the covered ozone nonattainment areas, the CAAA require that gasoline in all other areas not be any more polluting than it was in 1990. Without this "anti-dumping" provision, the potential exists for emissions from CG to worsen as polluting fuel components are removed from RFG.

3.2 REPRESENTATION OF NON-LINEAR EMISSIONS MODELS IN A LINEAR PROGRAM

The non-linear Complex Model presents difficult adaptation problems for use in refinery linear programs. Each gasoline blending component has VOC, TAP, and NO_x blending values that vary with overall gasoline composition. The Complex Model is represented in ORNL-RYM by a linear delta method in which off-line software computes coefficients of change of emissions with changes in a gasoline property. These coefficients are then used in the off-line software to compute emissions blending values for the gasoline blending components. ORNL-RYM is solved iteratively, until convergence of the solutions.

4. STUDY PREMISES

There are three key premises for the ethanol demand study. First, it is assumed that gasoline blending is optimized, with minimum giveaway of gasoline quality. Modeled refineries can produce subgrade gasolines for shipment to blenders who add optimal volumes of ethanol to produce finished gasoline. Second, ethanol handling and logistics costs in refining/blending are assumed to be 10 cents per gallon. The handling and logistics costs are within the range of cost estimates reported by Anderson et al. (1988) and Czeskleba (1993). Third, it is assumed that consumers are indifferent to ethanol blends, neither seeking nor avoiding these gasolines (Anderson et al. 1988).

The more detailed premise data for regional and seasonal product slates and revenues, raw materials and costs, and process capacity for the ethanol demand study are shown in Tables 2 through 19. These data are based on the specific assumptions and sources discussed in the following paragraphs.

4.1 REFINERY PRODUCTS

Regional refinery product output is based on the *Petroleum Supply Annual* (DOE 1996d; DOE 1998) and on the California Energy Commission's *Weekly Fuels Watch Report* (CEC 1998b). Annual product output is extrapolated to year 2010 with growth rates reported in the *Annual Energy Outlook 1996* (DOE 1996a). Annual production is seasonalized with factors developed by the last NPC study of gasoline reformulation (NPC 1993). Four gasoline pools are represented in the study:

1. CG with ethers.
2. CG with ethanol. Ethanol blending may occur at the refinery, or a subgrade gasoline may be delivered to a downstream blending terminal for finishing.
3. RFG with ethers. In the winter, this RFG pool is modeled to capture the weighted properties of both winter RFG and gasoline for winter CO nonattainment regions.
4. RFG with ethanol. Ethanol blending may occur at the refinery, or a subgrade gasoline may be delivered to a downstream blending terminal for finishing. In the winter, this RFG pool is modeled to capture the weighted properties of both winter RFG and gasoline for winter CO nonattainment regions.

The RFG share of total gasoline production in year 2010 is the same as recently reported in the *Motor Gasoline Watch* (DOE 1997b), in *Petroleum Supply Annual* (DOE 1996d; DOE 1998), and in the CEC's *Weekly Fuels Watch Report* (CEC 1998b). The RFG production shares range from 12 percent in PADD II to 87 percent in California. Exploratory ORNL-RYM runs suggest that ethanol demand can be quite sensitive to RFG share (see Section 7.1). The premised RFG shares maximize the demand for ethanol in gasoline production and finishing.

Gasoline quality surveys of the NPRA (1991) and of the American Petroleum Institute/National Petroleum Refiners Association (API/NPRA 1997) provide estimates of composite gasoline octanes for the gasoline pools. Gasoline properties are weighted by regional class fractions for gasolines sold in

Table 2. PADD I product slate for year 2010 reference conditions

Summer			Winter		
PRODUCT	\$/BARREL	MBD	PRODUCT	\$/BARREL	MBD
PROCESS GAS C2-FOE	15.16		PROCESS GAS C2-FOE	15.16	
STILL GAS TO PETROCHEM	15.16		STILL GAS TO PETROCHEM	15.16	
ETHANE FOE	15.16		ETHANE FOE	15.16	
ETHANE FOE	15.16		ETHANE FOE	15.16	
ETHYLENE FOE	15.16		ETHYLENE FOE	15.16	
PROPYLENE TO PETROCHEM	25.53		PROPYLENE TO PETROCHEM	27.24	
PROPANE FUEL(LPG)	21.66		PROPANE FUEL(LPG)	23.38	
PROPANE TO PETROCHEM	21.66		PROPANE TO PETROCHEM	23.38	
NORMAL BUTANE	19.61		NORMAL BUTANE	21.50	
SURPLUS NC4	19.61		SURPLUS NC4	21.50	
N BUTYLENE	26.50		N BUTYLENE	26.50	
ISO BUTANE	27.00		ISO BUTANE	27.00	
ISO BUTYLENE	26.50		ISO BUTYLENE	26.50	
*C2-C4 PRODUCTION SUMS TO	<49.6	MBD	*C2-C4 PRODUCTION SUMS TO	<51.3	MBD
CG WITH ETHERS	33.53		CG WITH ETHERS	29.63	
CG WITH ETHANOL	33.53		CG WITH ETHANOL	29.63	
*CG PRODUCTION SUMS TO	313.5	MBD EQUIVALENT	*CG PRODUCTION SUMS TO	315.8	MBD EQUIVALENT
RFG WITH ETHERS	34.87		RFG-OG WITH ETHERS	30.96	
RFG WITH ETHANOL	34.87		RFG-OG WITH ETHANOL	30.96	
*RFG PRODUCTION SUMS TO	500.7	MBD EQUIVALENT	*RFG PRODUCTION SUMS TO	504.5	MBD EQUIVALENT
AVIATION GAS	36.18	5.1	AVIATION GAS	32.05	5.1
MIL JET FUEL JP8	30.57	0.3	MIL JET FUEL JP8	34.35	0.3
COMMERCIAL JET A	30.51	122.1	COMMERCIAL JET A	34.30	127.2
2D ON-HIGHWAY DIESEL	30.17	160.5	2D ON-HIGHWAY DIESEL	33.60	168.4
HEATING OIL (NO2)	29.48	282	HEATING OIL (NO2)	32.92	296.2
RESIDUAL <.3S	22.57		RESIDUAL <.3S	20.85	
NET RESIDUAL 0.7-1.0 %	21.54		NET RESIDUAL 0.7-1.0 %	19.82	
BUNKER	20.32		BUNKER	18.61	
NAPHTHA TO P.CHEM	27.70		NAPHTHA TO P.CHEM	23.80	
AROMATICS TO P. CHEM	41.86		AROMATICS TO P. CHEM	37.96	
GAS OIL TO PETROCHEM	26.68		GAS OIL TO PETROCHEM	30.12	
*PETROCHEM PRODUCTION SUMS TO	9.3	MBD	*PETROCHEM PRODUCTION SUMS TO	16.7	MBD
LUBES & WAXES	39.21	20.6	LUBES & WAXES	37.50	20.4
COKE ST/CD LOW SULF	58.25		COKE ST/CD LOW SULF	56.64	
COKE ST/CD HIGH SULF	33.56		COKE ST/CD HIGH SULF	32.64	
COKE ST/CD XTRA HI SULF	7.80		COKE ST/CD XTRA HI SULF	7.59	
ROAD OIL & ASPHALT	21.78	<106.9	ROAD OIL & ASPHALT	20.07	<57.4
SULFUR	69.77		SULFUR	67.85	

Table 3. PADD I raw material options for year 2010 reference conditions

Summer			Winter		
CRUDE/RAW MATERIAL	\$/BARREL	MBD	CRUDE/RAW MATERIAL	\$/BARREL	MBD
ALGERIAN SAHARAN	28.60	2	ALGERIAN SAHARAN	28.97	2
KUWAIT	24.68	1	KUWAIT	24.76	1
SAUDI ARABIAN BERRI	25.70	2	SAUDI ARABIAN BERRI	25.78	2
SAUDI ARABIAN LIGHT	25.47		SAUDI ARABIAN LIGHT	25.56	
SAUDI ARABIAN MEDIUM	24.20	57	SAUDI ARABIAN MEDIUM	24.28	55
SAUDI ARABIAN HEAVY	23.52		SAUDI ARABIAN HEAVY	23.60	
GABON	25.15	112	GABON	25.52	109
NIGERIAN MEDIUM	24.69	207	NIGERIAN MEDIUM	25.06	200
NIGERIAN LIGHT	28.20	21	NIGERIAN LIGHT	28.57	21
NIGERIAN FORCADOS	26.22	76	NIGERIAN FORCADOS	26.59	74
VEN BACH 17 / 2.4	21.10	145	VEN BACH 17 / 2.4	21.18	140
VEN XHVY BOSCAN 11.2/4	20.10	43	VEN XHVY BOSCAN 11.2/4	20.18	42
ANGOLAN	25.36	241	ANGOLAN	25.73	234
CANADIAN INTERMED	26.55	67	CANADIAN INTERMED	26.63	65
CHINA BLEND	24.97	7	CHINA BLEND	25.06	7
COLOMBIAN	25.87	56	COLOMBIAN	25.96	55
CONGO	24.69	28	CONGO	25.06	27
ECUADOR	25.84	47	ECUADOR	25.92	47
EGYPT GHARIB/BAKR	24.50	<31	EGYPT GHARIB/BAKR	24.87	30
MEXICAN ISTHMUS	25.91	7	MEXICAN ISTHMUS	24.56	7
MEXICAN MAYA	22.54	17	MEXICAN MAYA	21.19	17
NORWAY	25.77	201	NORWAY	26.14	194
UK	25.77		UK	26.14	
OHIO LIGHT	27.47	26	OHIO LIGHT	26.98	25
NATURAL GAS (FOE)	20.57		NATURAL GAS (FOE)	21.59	
ISOBUTANE	27.86	<4.7	ISOBUTANE	27.86	<4.5
NORMAL BUTANE	20.47		NORMAL BUTANE	22.36	
ETHANOL	27.74		ETHANOL	27.74	
METHANOL	25.60		METHANOL	29.02	
MTBE	47.47		MTBE	54.53	
ETBE	47.90		ETBE	54.96	
NAPHTHA/REF FEED	27.96	<19.2	NAPHTHA/REF FEED	24.05	<18.6
GAS OIL MED S	27.33	<102.5	GAS OIL MED S	30.76	<99.2

Table 4. PADD I process capacity for year 2010 reference conditions

Summer		Winter	
PROCESS	CAPACITY MBSD	PROCESS	CAPACITY MBSD
CRUDE DISTILLATION	1583.2	CRUDE DISTILLATION	1583.2
VACUUM DISTILLATION	666.5	VACUUM DISTILLATION	675.2
FLUID CAT CRACKER	622	FLUID CAT CRACKER	622
HYDROCRACKER-2 STAGE	74.9	HYDROCRACKER-2 STAGE	74.9
HYDROCRACKER-LOW CONVER	0	HYDROCRACKER-LOW CONVER	0
RESID HYDROCRACKER	0	RESID HYDROCRACKER	0
COKER-DELAYED	89.5	COKER-DELAYED	89.5
VISBREAKER	10.9	VISBREAKER	10.9
SOLVENT DEASPHALTING	21	SOLVENT DEASPHALTING	21
LUBE + WAX PLANTS	35	LUBE + WAX PLANTS	35
NAPHTHA HYDROTREATER	343.9	NAPHTHA HYDROTREATER	343.9
DISTILLATE HDS	326	DISTILLATE HDS	326
MID DIST DEEP HT	65.2	MID DIST DEEP HT	81
FCC FEED HYDROFINER	74	FCC FEED HYDROFINER	74
VAC RESID DESULF	0	VAC RESID DESULF	0
ATM RESID DESULF	0	ATM RESID DESULF	0
M DIST FURFURAL TRTING	0	M DIST FURFURAL TRTING	0
GAS OIL DEWAXER	0	GAS OIL DEWAXER	0
HP SEMI REGEN REFORMER	166.4	HP SEMI REGEN REFORMER	166.4
LP CYCLIC REFORMER	39.2	LP CYCLIC REFORMER	39.2
LP CONTINUOUS REFORMER	124.5	LP CONTINUOUS REFORMER	124.5
ALKYLATION PLANT	83.4	ALKYLATION PLANT	83.4
CAT POLYMERIZATION	13.8	CAT POLYMERIZATION	13.8
DIMERSOL	3.5	DIMERSOL	3.5
BUTANE ISOMERIZATION	8.5	BUTANE ISOMERIZATION	8.5
PEN/HEX ISOMERIZATION	19.2	PEN/HEX ISOMERIZATION	19.2
TOTAL RECYCLE ISOM	0	TOTAL RECYCLE ISOM	0
AROMATICS RECOVERY(BTX)	33.4	AROMATICS RECOVERY(BTX)	33.4
MTBE(ETHEROL)	10.5	MTBE(ETHEROL)	10.5
TAME (ETHEROL)	0	TAME (ETHEROL)	0
DIPE (MOBIL)	0	DIPE (MOBIL)	0
C3/C4 DEHYDROGENATION	0	C3/C4 DEHYDROGENATION	0
C2 CRYOGENIC SPLITTER	0	C2 CRYOGENIC SPLITTER	0
DIMERN OF C2- TO C4-	0	DIMERN OF C2- TO C4-	0
HYDROGN OF NC5-/NC6-	0	HYDROGN OF NC5-/NC6-	0
ISOM OF 1C4- TO 2C4-	0	ISOM OF 1C4- TO 2C4-	0
CYCLAR UNIT	0	CYCLAR UNIT	0
OCTGAIN	0	OCTGAIN	0
ALKY OF BENZENE	0	ALKY OF BENZENE	0
NAPHTHA HYDROCRACKER	0	NAPHTHA HYDROCRACKER	0
TH CRACKER-LIGHT GAS	0	TH CRACKER-LIGHT GAS	0
TH CRACKER-NAPHTHA	0	TH CRACKER-NAPHTHA	0
TH CRACKER-VAC GAS OIL	0	TH CRACKER-VAC GAS OIL	0
REFORMATE SPLITTER	0	NAPHTHA SPLITTER	0
NAPHTHA SPLITTER	0	REFORMATE SPLITTER	0
FCC GASOLINE SPLR	0	FCC GASOLINE SPLR	37.3
JET RECUT SPLITTER	0	JET RECUT SPLITTER	1.1
LCCO PRE-FRACTIONATION	0	LCCO PRE-FRACTIONATION	0
BUTANE SPLITTER	0	BUTANE SPLITTER	0
HYDROGEN PLT,MBPD FOE	6.35	HYDROGEN PLT,MBPD FOE	6.35
HYDROGEN VIA PART OXY	0	HYDROGEN VIA PART OXY	0
SULFUR PLANT,MST/D	1.498	SULFUR PLANT,MST/D	1.498

Table 5. PADD II product slate for year 2010 reference conditions

Summer			Winter		
PRODUCT	\$/BARREL	MBD	PRODUCT	\$/BARREL	MBD
PROCESS GAS C2-FOE	14.99		PROCESS GAS C2-FOE	16.70	
STILL GAS TO PETROCHEM	14.99		STILL GAS TO PETROCHEM	16.70	
ETHANE FOE	14.99		ETHANE FOE	16.70	
ETHANE FOE	14.99		ETHANE FOE	16.70	
ETHYLENE FOE	14.99		ETHYLENE FOE	16.70	
PROPYLENE TO PETROCHEM	19.99		PROPYLENE TO PETROCHEM	21.70	
PROPANE FUEL(LPG)	16.12		PROPANE FUEL(LPG)	17.84	
PROPANE TO PETROCHEM	16.12		PROPANE TO PETROCHEM	17.84	
NORMAL BUTANE	19.61		NORMAL BUTANE	21.32	
SURPLUS NC4	19.61		SURPLUS NC4	21.32	
N BUTYLENE	20.31		N BUTYLENE	22.03	
ISO BUTANE	22.10		ISO BUTANE	23.82	
ISO BUTYLENE	21.60		ISO BUTYLENE	23.32	
CG WITH ETHERS	34.71		CG WITH ETHERS	29.64	
CG WITH ETHANOL	34.71		CG WITH ETHANOL	29.64	
*CG PRODUCTION SUMS TO 1698 MBD EQUIVALENT			*CG PRODUCTION SUMS TO 1618 MBD EQUIVALENT		
RFG WITH ETHERS	37.17		RFG WITH ETHERS	32.10	
RFG WITH ETHANOL	37.17		RFG WITH ETHANOL	32.10	
*RFG PRODUCTION SUMS TO 227 MBD EQUIVALENT			*RFG PRODUCTION SUMS TO 216 MBD EQUIVALENT		
AVIATION GAS	38.24	3.5	AVIATION GAS	33.17	3.6
MIL JET FUEL JP8	31.51	16.8	MIL JET FUEL JP8	32.79	16.8
COMMERCIAL JET A	31.46	243.3	COMMERCIAL JET A	32.74	268.6
2D ON-HIGHWAY DIESEL	30.68	575.2	2D ON-HIGHWAY DIESEL	31.97	599.9
HEATING OIL (NO2)	29.99	262.1	HEATING OIL (NO2)	30.73	273.4
RESIDUAL <.3S	19.93		RESIDUAL <.3S	18.69	
NET RESIDUAL 0.7-1.0 %	18.90		NET RESIDUAL 0.7-1.0 %	17.65	
BUNKER	17.69		BUNKER	16.44	
*RESID PRODUCTION SUMS TO 64.8 MBD			*RESID PRODUCTION SUMS TO 68.6 MBD		
NAPHTHA TO P.CHEM	28.64		NAPHTHA TO P.CHEM	23.57	
AROMATICS TO P. CHEM	42.80		AROMATICS TO P. CHEM	37.73	
GAS OIL TO PETROCHEM	27.88		GAS OIL TO PETROCHEM	28.61	
*PETROCHEM PRODUCTION SUMS TO 58.7 MBD			*PETROCHEM PRODUCTION SUMS TO 57.5 MBD		
LUBES & WAXES	39.13	25.8	LUBES & WAXES	31.75	25.3
COKE ST/CD LOW SULF	56.63		COKE ST/CD LOW SULF	56.63	
COKE ST/CD HIGH SULF	31.95		COKE ST/CD HIGH SULF	31.95	
COKE ST/CD XTRA HI SULF	6.18		COKE ST/CD XTRA HI SULF	6.18	
ROAD OIL & ASPHALT	21.70	218.0	ROAD OIL & ASPHALT	20.46	148.1
SULFUR	69.18		SULFUR	69.18	

Table 6. PADD II raw material options for year 2010 reference conditions

Summer			Winter		
CRUDE/RAW MATERIAL	\$/BARREL	MBD	CRUDE/RAW MATERIAL	\$/BARREL	MBD
KUWAIT	25.44	72	KUWAIT	25.53	47
SAUDI ARABIAN BERRI	26.47	5	SAUDI ARABIAN BERRI	26.55	5
SAUDI ARABIAN LIGHT	26.24	75	SAUDI ARABIAN LIGHT	26.32	69
SAUDI ARABIAN HEAVY	24.29	1	SAUDI ARABIAN MEDIUM	25.05	1
NIGERIAN MEDIUM	25.20	52	SAUDI ARABIAN HEAVY	24.37	1
NIGERIAN LIGHT	28.72	10	NIGERIAN MEDIUM	25.57	41
NIGERIAN FORCADOS	26.73	14	NIGERIAN LIGHT	29.08	8
VENEZ LAGO MED	25.18	200	NIGERIAN FORCADOS	27.10	12
ANGOLAN	25.87	14	VENEZ LAGO MED	23.83	189
CANADA LLOYDMINISTER	24.45	>278	ANGOLAN	26.24	87
CANADIAN INTRPRVN	26.22	84	CANADA LLOYDMINISTER	24.53	>303
CANADIAN RANGELAND	25.96	54	CANADIAN INTRPRVN	26.30	201
COLOMBIAN	26.18	47	CANADIAN RANGELAND	26.04	130
MEXICAN ISTHMUS	26.22	99	COLOMBIAN	24.83	15
MEXICAN MAYA	22.85	125	CONGO	25.57	13
OMAN	26.21	17	ECUADOR	25.30	5
RUSSIA	26.21	7	MEXICAN ISTHMUS	24.87	63
UK	26.54	21	MEXICAN MAYA	21.50	80
ALABAMA HVY	26.63	9	TRINIDAD SWEET LS	24.83	4
LOUISIANA LT SWEET	26.83	171	TRINIDAD SOUR HS	23.21	4
LOUISIANA S.MIX/OFFSHORE	27.06	137	UK	26.91	7
MISSISSIPPI HEY/OK VELMA	27.48	49	ALABAMA HVY	26.14	7
NEW MEXICO INT	29.03	114	LOUISIANA LT SWEET	26.34	135
TEXAS EAST	27.54	171	LOUISIANA S.MIX/OFFSHORE	26.57	108
TEXAS WEST INTERMED	27.70	>212	MISSISSIPPI HEY/OK VELMA	26.99	39
TEXAS WEST SOUR	26.36	569	NEW MEXICO INT	28.54	114
TEXAS SCURRY	27.58	65	TEXAS EAST	27.05	135
KENTUCKY SWEET	27.38	11	TEXAS WEST INTERMED	27.21	>124
MICHIGAN SWEET	27.91	38	TEXAS WEST SOUR	26.02	450
S. DAKOTA SWEET	27.06	4	TEXAS SCURRY	27.09	51
KANSAS SWEET	28.07	98	KENTUCKY SWEET	26.89	9
ILLINOIS SWEET	27.91	36	MICHIGAN SWEET	27.42	30
INDIANA SWEET	27.38	6	S. DAKOTA SWEET	26.57	3
OKLAHOMA GARBER	28.07	81	KANSAS SWEET	27.58	77
OKLA CONDENSATE	29.40	8	ILLINOIS SWEET	27.42	28
OKLA CEMENT	25.13	69	INDIANA SWEET	26.89	5
COLORADO RANGELY	27.00	1	OKLAHOMA GARBER	27.58	64
WYOMING SWEET	27.06	18	OKLA CONDENSATE	28.91	6
WYOMING SOUR	24.30	20	OKLA CEMENT	24.64	55
ALASKAN NORTH SLOPE	25.56	19	COLORADO RANGELY	26.51	1
NATURAL GAS (FOE)	18.64		WYOMING SWEET	26.57	14
NATURAL GASOLINE	28.36	<51.3	WYOMING SOUR	23.81	16
ISOBUTANE	23.79	<39.6	ALASKAN NORTH SLOPE	25.52	12
NORMAL BUTANE	19.75		NATURAL GAS (FOE)	19.66	
ETHANOL	27.74		NATURAL GASOLINE	23.29	<40
METHANOL	26.96		ISOBUTANE	23.79	<47.1
MTBE	49.53		NORMAL BUTANE	21.64	
ETBE	49.96		ETHANOL	21.73	
NAPHTHA/REF FEED	29.13	<32	METHANOL	26.10	
GAS OIL	27.84	<13.9	MTBE	50.39	
			ETBE	50.82	
			NAPHTHA/REF FEED	24.06	<51.5
			GAS OIL	28.57	<22.4

Table 7. PADD II process capacity for year 2010 reference conditions

Summer		Winter	
PROCESS	CAPACITY MBSD	PROCESS	CAPACITY MBSD
CRUDE DISTILLATION	3734.7	CRUDE DISTILLATION	3734.7
VACUUM DISTILLATION	1456.2	VACUUM DISTILLATION	1456.2
FLUID CAT CRACKER	1295.8	FLUID CAT CRACKER	1295.8
HYDROCRACKER-2 STAGE	130.8	HYDROCRACKER-2 STAGE	130.8
HYDROCRACKER-LOW CONVER	21.4	HYDROCRACKER-LOW CONVER	21.4
RESID HYDROCRACKER	0	RESID HYDROCRACKER	0
COKER-DELAYED	341	COKER-DELAYED	341
VISBREAKER	64.5	VISBREAKER	96.2
SOLVENT DEASPHALTING	30.2	SOLVENT DEASPHALTING	30.2
LUBE + WAX PLANTS	29.8	LUBE + WAX PLANTS	29.8
NAPHTHA HYDROTREATER	1137.9	NAPHTHA HYDROTREATER	1137.9
DISTILLATE HDS	914.8	DISTILLATE HDS	914.8
MID DIST DEEP HT	0	MID DIST DEEP HT	201.1
FCC FEED HYDROFINER	431.6	FCC FEED HYDROFINER	431.6
VAC RESID DESULF	0	VAC RESID DESULF	0
ATM RESID DESULF	13	ATM RESID DESULF	13
M DIST FURFURAL TRTING	0	M DIST FURFURAL TRTING	0
GAS OIL DEWAXER	0	GAS OIL DEWAXER	0
HP SEMI REGEN REFORMER	543.4	HP SEMI REGEN REFORMER	543.4
LP CYCLIC REFORMER	88.5	LP CYCLIC REFORMER	88.5
LP CONTINUOUS REFORMER	303.2	LP CONTINUOUS REFORMER	303.2
ALKYLATION PLANT	275.9	ALKYLATION PLANT	275.9
CAT POLYMERIZATION	13	CAT POLYMERIZATION	13
DIMERSOL	4.5	DIMERSOL	4.5
BUTANE ISOMERIZATION	22	BUTANE ISOMERIZATION	22
PEN/HEX ISOMERIZATION	165.7	PEN/HEX ISOMERIZATION	165.7
TOTAL RECYCLE ISOM	0	TOTAL RECYCLE ISOM	0
AROMATICS RECOVERY(BTX)	49.7	AROMATICS RECOVERY(BTX)	49.7
MTBE(ETHEROL)	12.2	MTBE(ETHEROL)	12.2
DIPE (MOBIL)	0	DIPE (MOBIL)	0
TH CRACKER-VAC GAS OIL	0	TH CRACKER-VAC GAS OIL	0
NAPHTHA SPLITTER	0	NAPHTHA SPLITTER	0
REFORMATE SPLITTER	0	REFORMATE SPLITTER	0
FCC GASOLINE SPLR	0	FCC GASOLINE SPLR	0
BUTANE SPLITTER	0	BUTANE SPLITTER	0
HYDROGEN PLT,MBPD FOE	19.65	HYDROGEN PLT,MBPD FOE	19.65
SULFUR PLANT,MST/D	4.47	SULFUR PLANT,MST/D	4.47

Table 8. PADD III product slate for year 2010 reference conditions

Summer			Winter		
PRODUCT	\$/BARREL	MBD	PRODUCT	\$/BARREL	MBD
PROCESS GAS C2-FOE	15.67		PROCESS GAS C2-FOE	17.13	
STILL GAS TO PETROCHEM	15.67		STILL GAS TO PETROCHEM	17.13	
ETHANE FOE	15.67		ETHANE FOE	17.13	
ETHANE FOE	15.67		ETHANE FOE	17.13	
ETHYLENE FOE	15.67		ETHYLENE FOE	17.13	
PROPYLENE TO PETROCHEM	20.67		PROPYLENE TO PETROCHEM	22.13	
PROPANE FUEL(LPG)	16.81		PROPANE FUEL(LPG)	18.27	
PROPANE TO PETROCHEM	16.81		PROPANE TO PETROCHEM	18.27	
NORMAL BUTANE	20.12		NORMAL BUTANE	20.12	
SURPLUS NC4	20.12		SURPLUS NC4	20.12	
N BUTYLENE	21.00		N BUTYLENE	21.00	
ISO BUTANE	21.50		ISO BUTANE	21.50	
ISO BUTYLENE	21.00		ISO BUTYLENE	21.00	
CG WITH ETHERS	32.24		CG/OG WITH ETHERS	28.86	
CG WITH ETHANOL	32.24		CG/OG WITH ETHANOL	28.86	
*CG PRODUCTION SUMS TO 2982 MBD EQUIVALENT			*CG PRODUCTION SUMS TO 2883 MBD EQUIVALENT		
RFG WITH ETHERS	33.58		RFG/OG WITH ETHERS	30.20	
RFG WITH ETHANOL	33.58		RFG/OG WITH ETHANOL	30.20	
*RFG PRODUCTION SUMS TO 640 MBD EQUIVALENT			*RFG PRODUCTION SUMS TO 619 MBD EQUIVALENT		
AVIATION GAS	34.89	14	AVIATION GAS	31.51	14
MIL JET FUEL JP8	29.53	139.6	MIL JET FUEL JP8	32.62	139.5
COMMERCIAL JET A	29.48	728.7	COMMERCIAL JET A	32.86	808.5
2D ON-HIGHWAY DIESEL	29.13	950.3	2D ON-HIGHWAY DIESEL	31.79	991.1
HEATING OIL (NO2)	28.45	563.8	HEATING OIL (NO2)	31.11	588
RESIDUAL <.3S	21.98		RESIDUAL <.3S	20.73	
NET RESIDUAL 0.7-1.0 %	20.95	85.7	NET RESIDUAL 0.7-1.0 %	19.70	90.6
BUNKER	19.73		BUNKER	18.48	
*RESID PRODUCTION SUMS TO 358.4 MBD			*RESID PRODUCTION SUMS TO 379.0 MBD		
NAPHTHA TO P.CHEM	26.42		NAPHTHA TO P.CHEM	23.03	
AROMATICS TO P. CHEM	40.57		AROMATICS TO P. CHEM	37.19	
GAS OIL TO PETROCHEM	25.65		GAS OIL TO PETROCHEM	28.31	
*PETROCHEM PRODUCTION SUMS TO 58.5 MBD			*PETROCHEM PRODUCTION SUMS TO 57.4 MBD		
LUBES & WAXES	38.62	112.1	LUBES & WAXES	38.62	121.9
COKE ST/CD LOW SULF	57.66		COKE ST/CD LOW SULF	57.66	
COKE ST/CD HIGH SULF	32.97		COKE ST/CD HIGH SULF	32.97	
COKE ST/CD XTRA HI SULF	7.21		COKE ST/CD XTRA HI SULF	7.21	
ROAD OIL & ASPHALT	21.19	136.0	ROAD OIL & ASPHALT	19.94	92.4
SULFUR	69.18		SULFUR	69.18	

Table 9. PADD III raw material options for year 2010 reference conditions

Summer			Winter		
CRUDE/RAW MATERIAL	\$/BARREL	MBD	CRUDE/RAW MATERIAL	\$/BARREL	MBD
ALGERIAN SAHARAN	28.60	24	KUWAIT	25.01	176
KUWAIT	24.93	152	SAUDI ARABIAN BERRI	26.04	189
SAUDI ARABIAN BERRI	25.96	173	SAUDI ARABIAN LIGHT	25.81	
SAUDI ARABIAN LIGHT	25.73		SAUDI ARABIAN MEDIUM	24.53	452
SAUDI ARABIAN MEDIUM	24.45	414	SAUDI ARABIAN HEAVY	23.86	
SAUDI ARABIAN HEAVY	23.78		UAE - DUBAI	25.81	13
UAE - DUBAI	25.73	9	GABON	25.52	165
GABON	25.15	202	NIGERIAN MEDIUM	25.06	152
INDONESIAN MINAS	25.51	3	NIGERIAN LIGHT	28.57	78
NIGERIAN MEDIUM	24.69	140	NIGERIAN FORCADOS	26.59	141
NIGERIAN LIGHT	28.20	72	VENEZ MED (TJ MED)	24.13	654
NIGERIAN FORCADOS	26.22	130	VEN BACH 17 / 2.4	20.98	358
VENEZ MED (TJ MED)	24.04	643	VEN XHVV BOSCAN 11.2/4	19.98	<10
VEN BACH 17 / 2.4	20.90	351	ANGOLAN	25.73	121
VEN XHVV BOSCAN 11.2/4	19.89	<10	CHINA BLEND	25.06	12
ANGOLAN	25.36	227	COLOMBIAN	25.75	180
COLOMBIAN	25.67	186	ECUADOR	25.72	132
CONGO	24.69	37	EGYPT GHARIB/BAKR	24.87	<19
ECUADOR	25.64	77	GUATEMALA	25.89	12
EGYPT GHARIB/BAKR	24.50	<28	MALAYSIA LABUAN	26.55	9
GUATEMALA	25.81	9	MEXICAN ISTHMUS	25.79	246
MALAYSIA LABUAN	26.47	3	MEXICAN MAYA	20.99	825
MEXICAN ISTHMUS	25.71	269	NORWAY	26.11	93
MEXICAN MAYA	22.34	902	TRINIDAD SWEET LS	27.07	30
NORWAY	26.03	187	TRINIDAD SOUR HS	25.30	30
OMAN	25.70	11	UK	26.39	<500
RUSSIA	25.70	49	ZAIRE	25.73	13
TRINIDAD SWEET LS	26.99	38	ALABAMA HVY	25.70	25
TRINIDAD SOUR HS	25.22	38	ALABAMA LIGHT	26.79	15
UK	26.03	<500	ARKANSAS	23.60	27
ZAIRE	25.36	18	LOUISIANA COND	26.97	92
ALABAMA HVY	26.12	23	LOUISIANA NORTH	26.84	53
ALABAMA LIGHT	27.21	14	LOUISIANA S.MIX/OFFSHORE	26.13	456
ARKANSAS	24.02	26	MISSISSIPPI HEY	26.55	16
LOUISIANA COND	27.39	86	MISSISSIPPI BAX	25.35	33
LOUISIANA NORTH	27.26	50	NEW MEXICO INT	28.10	20
LOUISIANA S.MIX/OFFSHORE	26.55	430	NEW MEXICO SOUR	25.43	40
MISSISSIPPI HEY	26.97	15	TEXAS CONDENSATE	28.88	69
MISSISSIPPI BAX	25.77	31	TEXAS GULF REF	26.23	403
NEW MEXICO INT	28.52	19	TEXAS EAST	26.61	64
NEW MEXICO SOUR	25.85	38	TEXAS HAWKINS	22.64	130
TEXAS CONDENSATE	29.30	65	TEXAS WEST INTERMED	26.70	364
TEXAS GULF REF	26.65	380	TEXAS WEST SOUR	25.51	87
TEXAS EAST	27.03	61	OKLA CEMENT	24.20	23
TEXAS HAWKINS	23.06	122	CALIFORNIA ELK HILLS	25.01	43
TEXAS WEST INTERMED	27.19	344	ALASKAN NORTH SLOPE	25.00	31
TEXAS WEST SOUR	25.85	83	NATURAL GAS (FOE)	17.73	
OKLA CEMENT	24.62	22	NATURAL GASOLINE	22.75	<104
CALIFORNIA ELK HILLS	25.43	41	ISOBUTANE	22.36	<86
ALASKAN NORTH SLOPE	25.05	21	NORMAL BUTANE	20.98	
NATURAL GAS (FOE)	16.70		ETHANOL	21.73	
NATURAL GASOLINE	26.13	<109	METHANOL	24.74	
ISOBUTANE	22.36	<97	MTBE	48.33	
NORMAL BUTANE	20.98		ETBE	48.76	
ETHANOL	27.74		NAPHTHA/REF FEED	23.29	<73.5
METHANOL	25.60		GAS OIL	28.95	<125.7
MTBE	47.47				
ETBE	47.90				
NAPHTHA/REF FEED	26.67	<68.2			
GAS OIL	26.29	<116.7			

Table 10. PADD III process capacity for year 2010 reference conditions

Summer		Winter	
PROCESS	CAPACITY MBSD	PROCESS	CAPACITY MBSD
CRUDE DISTILLATION	7545.2	CRUDE DISTILLATION	7545.2
VACUUM DISTILLATION	3400	VACUUM DISTILLATION	3400
FLUID CAT CRACKER	2643.4	FLUID CAT CRACKER	2643.4
HYDROCRACKER-2 STAGE	527	HYDROCRACKER-2 STAGE	527
HYDROCRACKER-LOW CONVER	105	HYDROCRACKER-LOW CONVER	105
RESID HYDROCRACKER	0	RESID HYDROCRACKER	0
COKER-DELAYED	788	COKER-DELAYED	788
VISBREAKER	31.4	VISBREAKER	31.4
SOLVENT DEASPHALTING	174	SOLVENT DEASPHALTING	217.8
LUBE + WAX PLANTS	131.1	LUBE + WAX PLANTS	131.1
NAPHTHA HYDROTREATER	1925	NAPHTHA HYDROTREATER	1925
DISTILLATE HDS	1880.2	DISTILLATE HDS	1880.2
MID DIST DEEP HT	274.771	MID DIST DEEP HT	317.2
FCC FEED HYDROFINER	886.4	FCC FEED HYDROFINER	886.4
VAC RESID DESULF	0	VAC RESID DESULF	0
ATM RESID DESULF	328	ATM RESID DESULF	328
M DIST FURFURAL TRYING	0	M DIST FURFURAL TRYING	0
GAS OIL DEWAXER	0	GAS OIL DEWAXER	0
HP SEMI REGEN REFORMER	649.1	HP SEMI REGEN REFORMER	649.1
LP CYCLIC REFORMER	323	LP CYCLIC REFORMER	323
LP CONTINUOUS REFORMER	890	LP CONTINUOUS REFORMER	890
ALKYLATION PLANT	545.5	ALKYLATION PLANT	545.5
CAT POLYMERIZATION	27.3	CAT POLYMERIZATION	27.3
DIMERSOL	11.5	DIMERSOL	11.5
BUTANE ISOMERIZATION	46.7	BUTANE ISOMERIZATION	46.7
PEN/HEX ISOMERIZATION	186.8	PEN/HEX ISOMERIZATION	186.8
TOTAL RECYCLE ISOM	0	TOTAL RECYCLE ISOM	0
AROMATICS RECOVERY(BTX)	212.7	AROMATICS RECOVERY(BTX)	212.7
MTBE(ETHEROL)	104.1	MTBE(ETHEROL)	104.1
DIPE (MOBIL)	0	DIPE (MOBIL)	0
TH CRACKER-VAC GAS OIL	0	TH CRACKER-VAC GAS OIL	0
NAPHTHA SPLITTER	0	NAPHTHA SPLITTER	0
REFORMATE SPLITTER	0	REFORMATE SPLITTER	0
FCC GASOLINE SPLR	0	FCC GASOLINE SPLR	0
BUTANE SPLITTER	0	BUTANE SPLITTER	0
HYDROGEN PLT,MBPD FOE	68.6	HYDROGEN PLT,MBPD FOE	68.6
SULFUR PLANT,MST/D	14.57	SULFUR PLANT,MST/D	14.57

Table 11. California product slate for year 2010 reference conditions

Summer			Winter		
PRODUCT	\$/BARREL	MBD	PRODUCT	\$/BARREL	MBD
PROCESS GAS C2-FOE	17.67		PROCESS GAS C2-FOE	17.30	
STILL GAS TO PETROCHEM	17.67		STILL GAS TO PETROCHEM	17.30	
ETHANE FOE	17.67		ETHANE FOE	17.30	
ETHANE FOE	17.67		ETHANE FOE	17.30	
ETHYLENE FOE	17.67		ETHYLENE FOE	17.30	
PROPYLENE TO PETROCHEM	28.87		PROPYLENE TO PETROCHEM	30.77	
PROPANE FUEL(LPG)	25.00		PROPANE FUEL(LPG)	26.72	
PROPANE TO PETROCHEM	25.00		PROPANE TO PETROCHEM	26.72	
NORMAL BUTANE	22.69		NORMAL BUTANE	24.59	
SURPLUS NC4	22.69		SURPLUS NC4	24.59	
N BUTYLENE	23.57		N BUTYLENE	25.46	
ISO BUTANE	30.04		ISO BUTANE	30.04	
ISO BUTYLENE	23.57		ISO BUTYLENE	23.57	
CG WITH ETHERS	34.78		CG WITH ETHERS	30.60	
CG WITH ETHANOL	34.78		CG WITH ETHANOL	30.60	
*CG PRODUCTION SUMS TO 146.6 MBD EQUIVALENT			*CG PRODUCTION SUMS TO 120.4 MBD EQUIVALENT		
CARB RFG WITH ETHERS	36.12		CARB RFG WITH ETHERS	31.94	
CARB RFG WITH ETHANOL	36.12		CARB RFG WITH ETHANOL	31.94	
*RFG PRODUCTION SUMS TO 914.9 MBD EQUIVALENT			*RFG PRODUCTION SUMS TO 859.1 MBD EQUIVALENT		
AVIATION GAS	37.43	3.1	AVIATION GAS	33.23	3
MIL JET FUEL JP8	31.76	30.1	MIL JET FUEL JP8	34.13	27.4
COMMERCIAL JET A	32.02	346.5	COMMERCIAL JET A	34.34	283.5
CARB DIESEL	33.04	183.3	CARB DIESEL	35.53	141.8
OTHER DIESEL	30.21	138.5	OTHER DIESEL	32.70	126.6
RESIDUAL <.3S	22.05		RESIDUAL <.3S	21.40	
NET RESIDUAL 0.7-1.0 %	21.02		NET RESIDUAL 0.7-1.0 %	20.36	
BUNKER	19.80		BUNKER	19.15	
*RESID PRODUCTION SUMS TO 200 MBD			*RESID PRODUCTION SUMS TO 200 MBD		
NAPHTHA TO P.CHEM	29.77		NAPHTHA TO P.CHEM	25.59	
AROMATICS TO P. CHEM	43.93		AROMATICS TO P. CHEM	39.75	
GAS OIL TO PETROCHEM	27.41		GAS OIL TO PETROCHEM	29.90	
LUBES & WAXES	38.82	17.1	LUBES & WAXES	37.05	16.8
COKE ST/CD LOW SULF	57.94		COKE ST/CD LOW SULF	55.30	
COKE ST/CD HIGH SULF	33.13		COKE ST/CD HIGH SULF	31.62	
COKE ST/CD XTRA HI SULF	7.25		COKE ST/CD XTRA HI SULF	6.92	
ROAD OIL & ASPHALT	21.29	<47.3	ROAD OIL & ASPHALT	20.64	<27.9
SULFUR	69.52		SULFUR	66.36	

Table 12. California raw material options for year 2010 reference conditions

Summer			Winter		
CRUDE/RAW MATERIAL*	\$/BARREL	MBD	CRUDE/RAW MATERIAL*	\$/BARREL	MBD
KUWAIT	24.58	5.7	KUWAIT	24.66	5.0
IRAQ	25.28	8.8	IRAQ	25.36	7.7
SAUDI ARABIAN BERRI	25.60	0.3	SAUDI ARABIAN BERRI	25.68	0.3
SAUDI LIGHT	25.37	131.1	SAUDI LIGHT	25.45	114.9
SAUDI ARABIAN MEDIUM	24.09	96.8	SAUDI ARABIAN MEDIUM	24.18	115.4
SAUDI ARABIAN HEAVY	23.42	0.6	SAUDI ARABIAN HEAVY	23.50	0.6
INDO MINAS	25.15	18.5	INDO MINAS	25.23	16.5
INDO ATTAKA	27.53	6.5	INDO ATTAKA	27.61	3.1
VENEZ MED (TJ MED)	24.55	177.4	VENEZ MED (TJ MED)	24.64	156.1
VEN BACH 17 / 2.4	21.41	2.3	VEN BACH 17 / 2.4	21.49	2.0
ARGENTINA	26.19	6.5	ARGENTINA	26.27	5.7
PERU	24.77	11.8	PERU	24.85	10.3
COLOMBIAN	25.27	69.8	COLOMBIAN	25.35	61.6
ECUADOR	25.24	6.5	ECUADOR	25.32	5.7
AUSTRALIA	27.45	7.8	AUSTRALIA	27.53	6.8
CANADIAN LLOYDMIN	23.82	25.7	CANADIAN LLOYDMIN	23.90	139.5
CHINA BLEND	24.46	17.5	CHINA BLEND	24.54	15.9
MALAYSIA LABUAN	26.07	2.8	MALAYSIA LABUAN	26.15	2.7
MEXICAN ISTHMUS	25.31	68.8	MEXICAN ISTHMUS	25.39	60.7
MEXICAN MAYA	21.94	2.6	MEXICAN MAYA	22.02	2.3
OMAN	25.30	2.0	OMAN	25.38	0.9
CALIFORNIA ELK HILLS	25.73	52.5	CALIFORNIA ELK HILLS	24.54	45.6
CALIFORNIA SAN ARDO	20.74	53.8	CALIFORNIA SAN ARDO	19.56	60.7
CALIFORNIA OCS	21.20	60.5	CALIFORNIA OCS	20.02	53.1
CALIFORNIA SJV	20.97	369.7	CALIFORNIA SJV	19.78	324.5
CALIFORNIA WILMINGTON	22.71	114.3	CALIFORNIA WILMINGTON	21.53	100.3
CALIFORNIA VENTURA	26.63	40.3	CALIFORNIA VENTURA	25.44	35.4
ALASKAN NORTH SLOPE	25.01	592.3	ALASKAN NORTH SLOPE	24.81	520.0
ALASKAN COOK	26.53	7.0	ALASKAN COOK	26.32	6.2
NATURAL GAS (FOE)	25.08		NATURAL GAS (FOE)	26.10	
NATURAL GASOLINE	28.66	<10.4	NATURAL GASOLINE	24.48	<9.1
ISOBUTANE	30.90	<8.5	ISOBUTANE	30.90	<7.5
NORMAL BUTANE	23.55		NORMAL BUTANE	25.44	
ETHANOL	27.74		ETHANOL	27.74	
METHANOL	27.74		METHANOL	26.89	
MTBE	47.47		MTBE	48.33	
ETBE	47.89		ETBE	48.76	
NAPHTHA/REF FEED	29.21	<25.2	NAPHTHA/REF FEED	25.03	<22.1
GAS OIL	29.07	<17	GAS OIL	31.57	<14.9
GAS OIL	28.05	<59.5	GAS OIL	30.55	<52.2
GASOLINE BLEND STOCKS	36.07	<42.6	GASOLINE BLEND STOCKS	32.91	<37.4
*CRUDE MBD INCLUDES LIMITED SWING FLEXIBILITY FOR ALL CRUDE OILS.					

Table 13. California process capacity for year 2010 reference conditions

Summer		Winter	
PROCESS	CAPACITY MBSD	PROCESS	CAPACITY MBSD
CRUDE DISTILLATION	1997.8	CRUDE DISTILLATION	2020.9
VACUUM DISTILLATION	1179	VACUUM DISTILLATION	1179
FLUID CAT CRACKER	652	FLUID CAT CRACKER	652
HYDROCRACKER-2 STAGE	470	HYDROCRACKER-2 STAGE	470
HYDROCRACKER-LOW CONVER	0	HYDROCRACKER-LOW CONVER	0
RESID HYDROCRACKER	0	RESID HYDROCRACKER	0
COKER FLUID	0	COKER FLUID	0
COKER-DELAYED	488	COKER-DELAYED	488
VISBREAKER	11	VISBREAKER	11
SOLVENT DEASPHALTING	50	SOLVENT DEASPHALTING	73.0
LUBE + WAX PLANTS	26	LUBE + WAX PLANTS	26
NAPHTHA HYDROTREATER	519	NAPHTHA HYDROTREATER	525.3
DISTILLATE HDS	406	DISTILLATE HDS	406
MID DIST DEEP HT	89	MID DIST DEEP HT	89
FCC FEED HYDROFINER	583	FCC FEED HYDROFINER	583
VAC RESID DESULF	0	VAC RESID DESULF	0
ATM RESID DESULF	0	ATM RESID DESULF	0
M DIST FURFURAL TRTING	0	M DIST FURFURAL TRTING	0
GAS OIL DEWAXER	0	GAS OIL DEWAXER	0
HP SEMI REGEN REFORMER	226	HP SEMI REGEN REFORMER	226
LP CYCLIC REFORMER	120	LP CYCLIC REFORMER	120
LP CONTINUOUS REFORMER	53	LP CONTINUOUS REFORMER	53
ALKYLATION PLANT	160	ALKYLATION PLANT	160
CAT POLYMERIZATION	7	CAT POLYMERIZATION	7
DIMERSOL	4.9	DIMERSOL	4.9
BUTANE ISOMERIZATION	12	BUTANE ISOMERIZATION	12
PEN/HEX ISOMERIZATION	89	PEN/HEX ISOMERIZATION	89
TOTAL RECYCLE ISOM	0	TOTAL RECYCLE ISOM	0
AROMATICS RECOVERY(BTX)	4.5	AROMATICS RECOVERY(BTX)	182.1
MTBE(ETHEROL)	18.1	MTBE(ETHEROL)	18.1
DIPE (MOBIL)	0	DIPE (MOBIL)	0
C3/C4 DEHYDROGENATION	0	C3/C4 DEHYDROGENATION	0
C2 CRYOGENIC SPLITTER	0	C2 CRYOGENIC SPLITTER	0
DIMERN OF C2- TO C4-	0	DIMERN OF C2- TO C4-	0
HYDROGN OF NC5-/NC6-	0	HYDROGN OF NC5-/NC6-	0
ISOM OF 1C4- TO 2C4-	0	ISOM OF 1C4- TO 2C4-	0
CYCLAR UNIT	0	CYCLAR UNIT	0
OCTGAIN	0	OCTGAIN	17.0
ALKY OF BENZENE	0	ALKY OF BENZENE	0
NAPHTHA HYDROCRACKER	0	NAPHTHA HYDROCRACKER	0
TH CRACKER-LIGHT GAS	0	TH CRACKER-LIGHT GAS	0
TH CRACKER-NAPHTHA	0	TH CRACKER-NAPHTHA	0
TH CRACKER-VAC GAS OIL	0	TH CRACKER-VAC GAS OIL	0
NAPHTHA SPLITTER	152.4	NAPHTHA SPLITTER	152.4
REFORMATE SPLITTER	0	REFORMATE SPLITTER	0
FCC GASOLINE SPLR	277.4	FCC GASOLINE SPLR	277.4
JET RECUT SPLITTER	0	JET RECUT SPLITTER	0
LCCO PRE-FRACTIONATION	0	LCCO PRE-FRACTIONATION	0
BUTANE SPLITTER	0	BUTANE SPLITTER	0
HYDROGEN PLT,MBPD FOE	76.4	HYDROGEN PLT,MBPD FOE	76.4
HYDROGEN VIA PART OXY	0	HYDROGEN VIA PART OXY	0
SULFUR PLANT,MST/D	4.86	SULFUR PLANT,MST/D	4.86

Table 14. PADD II product slate for year 2010 higher ethanol demand conditions

Summer			Winter		
PRODUCT	\$/BARREL	MBD	PRODUCT	\$/BARREL	MBD
PROCESS GAS C2-FOE	19.41		PROCESS GAS C2-FOE	21.63	
STILL GAS TO PETROCHEM	19.41		STILL GAS TO PETROCHEM	21.63	
ETHANE FOE	19.41		ETHANE FOE	21.63	
ETHANE FOE	19.41		ETHANE FOE	21.63	
ETHYLENE FOE	19.41		ETHYLENE FOE	21.63	
PROPYLENE TO PETROCHEM	25.88		PROPYLENE TO PETROCHEM	28.11	
PROPANE FUEL(LPG)	20.88		PROPANE FUEL(LPG)	23.10	
PROPANE TO PETROCHEM	20.88		PROPANE TO PETROCHEM	23.10	
NORMAL BUTANE	25.39		NORMAL BUTANE	27.62	
SURPLUS NC4	25.39		SURPLUS NC4	27.62	
N BUTYLENE	26.31		N BUTYLENE	28.53	
ISO BUTANE	28.62		ISO BUTANE	30.85	
ISO BUTYLENE	27.98		ISO BUTYLENE	30.20	
CG WITH ETHERS	45.98		CG WITH ETHERS	41.19	
CG WITH ETHANOL	45.98		CG WITH ETHANOL	41.19	
*CG PRODUCTION SUMS TO 1750 MBD EQUIVALENT			*CG PRODUCTION SUMS TO 1668 MBD EQUIVALENT		
RFG WITH ETHERS	48.45		RFG WITH ETHERS	43.65	
RFG WITH ETHANOL	48.45		RFG WITH ETHANOL	43.65	
*RFG PRODUCTION SUMS TO 234 MBD EQUIVALENT			*RFG PRODUCTION SUMS TO 223 MBD EQUIVALENT		
AVIATION GAS	49.52	3.6	AVIATION GAS	44.72	3.7
MIL JET FUEL JP8	42.78	18.2	MIL JET FUEL JP8	44.35	18.2
COMMERCIAL JET A	42.73	263	COMMERCIAL JET A	44.29	290.2
2D ON-HIGHWAY DIESEL	41.95	613.1	2D ON-HIGHWAY DIESEL	43.52	639.4
HEATING OIL (NO2)	41.27	277.5	HEATING OIL (NO2)	42.28	289.4
RESIDUAL <.3S	27.43		RESIDUAL <.3S	25.71	
NET RESIDUAL 0.7-1.0 %	26.01		NET RESIDUAL 0.7-1.0 %	24.29	
BUNKER	24.33		BUNKER	22.62	
*RESID PRODUCTION SUMS TO 64.9 MBD			*RESID PRODUCTION SUMS TO 68.7 MBD		
NAPHTHA TO P.CHEM	39.92		NAPHTHA TO P.CHEM	35.12	
AROMATICS TO P. CHEM	54.08		AROMATICS TO P. CHEM	49.28	
GAS OIL TO PETROCHEM	39.15		GAS OIL TO PETROCHEM	40.16	
*PETROCHEM PRODUCTION SUMS TO 58.7 MBD			*PETROCHEM PRODUCTION SUMS TO 57.5 MBD		
LUBES & WAXES	53.84	27.1	LUBES & WAXES	43.69	26.6
COKE ST/CD LOW SULF	77.93		COKE ST/CD LOW SULF	77.93	
COKE ST/CD HIGH SULF	43.96		COKE ST/CD HIGH SULF	43.96	
COKE ST/CD XTRA HI SULF	8.53		COKE ST/CD XTRA HI SULF	8.51	
ROAD OIL & ASPHALT	29.86	226.1	ROAD OIL & ASPHALT	29.90	153.6
SULFUR	69.18		SULFUR	69.18	

Table 15. PADD II raw material options for year 2010 higher ethanol demand conditions

Summer			Winter		
CRUDE/RAW MATERIAL	\$/BARREL	MBD	CRUDE/RAW MATERIAL	\$/BARREL	MBD
KUWAIT	35.01	75	KUWAIT	35.12	49
SAUDI ARABIAN BERRI	36.41	6	SAUDI ARABIAN BERRI	36.53	5
SAUDI ARABIAN LIGHT	36.11	79	SAUDI ARABIAN LIGHT	35.96	71
SAUDI ARABIAN MEDIUM	34.35	1	SAUDI ARABIAN MEDIUM	34.46	1
SAUDI ARABIAN HEAVY	33.42	1	SAUDI ARABIAN HEAVY	33.53	1
NIGERIAN MEDIUM	34.68	54	NIGERIAN MEDIUM	35.18	43
NIGERIAN LIGHT	39.51	10	NIGERIAN LIGHT	40.02	8
NIGERIAN FORCADOS	36.78	15	NIGERIAN FORCADOS	37.29	12
VENEZ LAGO MED	34.64	209	VENEZ LAGO MED	32.78	197
ANGOLAN	35.61	15	ANGOLAN	36.11	91
CANADA LLOYDMINISTER	33.64	>290	CANADA LLOYDMINISTER	33.76	>303
CANADIAN INTRPRVN	36.08	88	CANADIAN INTRPRVN	36.19	210
CANADIAN RANGELAND	35.72	56	CANADIAN RANGELAND	35.83	135
COLOMBIAN	36.02	49	COLOMBIAN	34.16	16
MEXICAN ISTHMUS	36.08	103	CONGO	35.18	14
MEXICAN MAYA	31.43	131	ECUADOR	34.82	5
OMAN	36.07	18	MEXICAN ISTHMUS	34.23	66
RUSSIA	36.07	7	MEXICAN MAYA	29.58	83
UK	36.52	21	TRINIDAD SWEET LS	34.16	4
ALABAMA HVY	36.64	9	TRINIDAD SOUR HS	31.93	4
LOUISIANA LT SWEET	36.92	178	UK	37.03	7
LOUISIANA S.MIX/OFFSHORE	37.23	142	ALABAMA HVY	35.96	7
MISSISSIPPI HEY/OK VELMA	37.81	51	LOUISIANA LT SWEET	36.25	141
NEW MEXICO INT	39.95	114	LOUISIANA S.MIX/OFFSHORE	36.56	113
TEXAS EAST	37.90	178	MISSISSIPPI HEY/OK VELMA	37.14	41
TEXAS WEST INTERMED	38.12	>220	NEW MEXICO INT	39.28	114
TEXAS WEST SOUR	36.28	592	TEXAS EAST	37.22	141
TEXAS SCURRY	37.95	68	TEXAS WEST INTERMED	37.45	>124
KENTUCKY SWEET	37.67	11	TEXAS WEST SOUR	35.80	468
MICHIGAN SWEET	38.40	39	TEXAS SCURRY	37.27	53
S. DAKOTA SWEET	37.23	4	KENTUCKY SWEET	37.00	9
KANSAS SWEET	38.62	101	MICHIGAN SWEET	37.72	31
ILLINOIS SWEET	38.40	37	S. DAKOTA SWEET	36.56	3
INDIANA SWEET	37.67	6	KANSAS SWEET	37.95	80
OKLAHOMA GARBER	38.62	84	ILLINOIS SWEET	37.72	30
OKLA CONDENSATE	40.45	8	INDIANA SWEET	37.00	5
OKLA CEMENT	34.57	72	OKLAHOMA GARBER	37.95	67
COLORADO RANGELY	37.15	1	OKLA CONDENSATE	39.78	6
WYOMING SWEET	37.23	19	OKLA CEMENT	33.90	57
WYOMING SOUR	33.44	21	COLORADO RANGELY	36.47	1
ALASKAN NORTH SLOPE	35.17	20	WYOMING SWEET	36.56	15
NATURAL GAS (FOE)	19.20		WYOMING SOUR	32.76	17
NATURAL GASOLINE	39.63	<56	ALASKAN NORTH SLOPE	35.10	12
ISOBUTANE	30.31	<43.2	NATURAL GAS (FOE)	20.28	
NORMAL BUTANE	25.54		NATURAL GASOLINE	34.84	<43.7
ETHANOL	27.74		ISOBUTANE	30.90	<51.4
METHANOL	27.35		NORMAL BUTANE	27.94	
MTBE	56.22		ETHANOL	21.73	
ETBE	56.65		METHANOL	26.61	
NAPHTHA/REF FEED	40.41	<32	MTBE	56.48	
GAS OIL	39.11	<13.9	ETBE	56.91	
			NAPHTHA/REF FEED	35.62	<51.5
			GAS OIL	40.12	<22.4

Table 16. PADD II process capacity for year 2010 higher ethanol demand conditions

Summer		Winter	
PROCESS	CAPACITY MBSD	PROCESS	CAPACITY MBSD
CRUDE DISTILLATION	3734.7	CRUDE DISTILLATION	3734.7
VACUUM DISTILLATION	1456.2	VACUUM DISTILLATION	1527.3
FLUID CAT CRACKER	1295.8	FLUID CAT CRACKER	1295.8
HYDROCRACKER-2 STAGE	130.8	HYDROCRACKER-2 STAGE	130.8
HYDROCRACKER-LOW CONVER	21.4	HYDROCRACKER-LOW CONVER	21.4
RESID HYDROCRACKER	0	RESID HYDROCRACKER	0
COKER-DELAYED	341	COKER-DELAYED	341
VISBREAKER	64.5	VISBREAKER	106
SOLVENT DEASPHALTING	30.2	SOLVENT DEASPHALTING	30.2
LUBE + WAX PLANTS	29.8	LUBE + WAX PLANTS	29.8
NAPHTHA HYDROTREATER	1137.9	NAPHTHA HYDROTREATER	1137.9
DISTILLATE HDS	914.8	DISTILLATE HDS	914.8
MID DIST DEEP HT	0	MID DIST DEEP HT	231
FCC FEED HYDROFINER	431.6	FCC FEED HYDROFINER	431.6
VAC RESID DESULF	0	VAC RESID DESULF	0
ATM RESID DESULF	13	ATM RESID DESULF	13
M DIST FURFURAL TRTING	0	M DIST FURFURAL TRTING	0
GAS OIL DEWAXER	0	GAS OIL DEWAXER	0
HP SEMI REGEN REFORMER	543.4	HP SEMI REGEN REFORMER	543.4
LP CYCLIC REFORMER	88.5	LP CYCLIC REFORMER	88.5
LP CONTINUOUS REFORMER	303.2	LP CONTINUOUS REFORMER	303.2
ALKYLATION PLANT	275.9	ALKYLATION PLANT	275.9
CAT POLYMERIZATION	13	CAT POLYMERIZATION	13
DIMERSOL	4.5	DIMERSOL	4.5
BUTANE ISOMERIZATION	22	BUTANE ISOMERIZATION	22
PEN/HEX ISOMERIZATION	165.7	PEN/HEX ISOMERIZATION	165.7
TOTAL RECYCLE ISOM	0	TOTAL RECYCLE ISOM	0
AROMATICS RECOVERY(BTX)	49.7	AROMATICS RECOVERY(BTX)	49.7
MTBE(ETHEROL)	12.2	MTBE(ETHEROL)	12.2
DIPE (MOBIL)	0	DIPE (MOBIL)	0
TH CRACKER-VAC GAS OIL	0	TH CRACKER-VAC GAS OIL	0
NAPHTHA SPLITTER	0	NAPHTHA SPLITTER	0
REFORMATE SPLITTER	0	REFORMATE SPLITTER	0
FCC GASOLINE SPLR	0	FCC GASOLINE SPLR	0
BUTANE SPLITTER	0	BUTANE SPLITTER	0
HYDROGEN PLT,MBPD FOE	19.65	HYDROGEN PLT,MBPD FOE	19.65
SULFUR PLANT,MST/D	4.47	SULFUR PLANT,MST/D	4.47

Table 17. PADD III product slate for year 2010 higher ethanol demand conditions

Summer			Winter		
PRODUCT	\$/BARREL	MBD	PRODUCT	\$/BARREL	MBD
PROCESS GAS C2-FOE	20.30		PROCESS GAS C2-FOE	22.19	
STILL GAS TO PETROCHEM	20.30		STILL GAS TO PETROCHEM	22.19	
ETHANE FOE	20.30		ETHANE FOE	22.19	
ETHANE FOE	20.30		ETHANE FOE	22.19	
ETHYLENE FOE	20.30		ETHYLENE FOE	22.19	
PROPYLENE TO PETROCHEM	26.77		PROPYLENE TO PETROCHEM	28.66	
PROPANE FUEL(LPG)	21.76		PROPANE FUEL(LPG)	23.67	
PROPANE TO PETROCHEM	21.76		PROPANE TO PETROCHEM	23.67	
NORMAL BUTANE	26.06		NORMAL BUTANE	26.06	
SURPLUS NC4	26.06		SURPLUS NC4	26.06	
N BUTYLENE	27.19		N BUTYLENE	27.19	
ISO BUTANE	27.95		ISO BUTANE	27.85	
ISO BUTYLENE	27.19		ISO BUTYLENE	27.19	
CG WITH ETHERS	42.94		CG/OG WITH ETHERS	40.55	
CG WITH ETHANOL	42.94		CG/OG WITH ETHANOL	40.55	
*CG PRODUCTION SUMS TO 3073 MBD EQUIVALENT			*CG PRODUCTION SUMS TO 2883 MBD EQUIVALENT		
RFG WITH ETHERS	44.27		RFG/OG WITH ETHERS	41.89	
RFG WITH ETHANOL	44.27		RFG/OG WITH ETHANOL	41.89	
*RFG PRODUCTION SUMS TO 660 MBD EQUIVALENT			*RFG PRODUCTION SUMS TO 619 MBD EQUIVALENT		
AVIATION GAS	45.50	14.5	AVIATION GAS	43.20	14.5
MIL JET FUEL JP8	40.23	150.8	MIL JET FUEL JP8	44.32	150.7
COMMERCIAL JET A	40.17	787.2	COMMERCIAL JET A	44.55	873.4
2D ON-HIGHWAY DIESEL	39.83	1012.9	2D ON-HIGHWAY DIESEL	43.49	1056.3
HEATING OIL (NO2)	39.14	596.8	HEATING OIL (NO2)	42.80	622.4
RESIDUAL <.3S	30.24		RESIDUAL <.3S	28.52	
NET RESIDUAL 0.7-1.0 %	28.82	85.8	NET RESIDUAL 0.7-1.0 %	27.10	90.8
BUNKER	27.15		BUNKER	25.43	
*RESID PRODUCTION SUMS TO 358.9 MBD			*RESID PRODUCTION SUMS TO 379.6 MBD		
AROMATICS TO P. CHEM	48.20	<58.5	NAPHTHA TO P.CHEM	34.73	
LUBES & WAXES	53.14	130.4	AROMATICS TO P. CHEM	48.88	
COKE ST/CD LOW SULF	79.33		GAS OIL TO PETROCHEM	40.00	
COKE ST/CD HIGH SULF	45.36		*PETROCHEM PRODUCTION SUMS TO 57.4 MBD		
COKE ST/CD XTRA HI SULF	9.92		LUBES & WAXES	53.14	127.8
ROAD OIL & ASPHALT	29.15	141.0	COKE ST/CD LOW SULF	79.33	
SULFUR	69.18		COKE ST/CD HIGH SULF	45.36	
			COKE ST/CD XTRA HI SULF	9.92	
			ROAD OIL & ASPHALT	29.15	95.8
			SULFUR	69.18	

Table 18. PADD III raw material options for year 2010 higher ethanol demand conditions

Summer			Winter		
CRUDE/RAW MATERIAL	\$/BARREL	MBD	CRUDE/RAW MATERIAL	\$/BARREL	MBD
ALGERIAN SAHARAN	39.36	25	KUWAIT	34.42	184
KUWAIT	34.31	158	SAUDI ARABIAN BERRI	35.83	197
SAUDI ARABIAN BERRI	35.72	180	SAUDI ARABIAN LIGHT	35.51	
SAUDI ARABIAN LIGHT	35.40		SAUDI ARABIAN MEDIUM	33.76	470
SAUDI ARABIAN MEDIUM	33.64	430	SAUDI ARABIAN HEAVY	32.82	
SAUDI ARABIAN HEAVY	32.71		UAE - DUBAI	35.51	13
UAE - DUBAI	35.40	9	GABON	35.10	172
GABON	34.60	210	NIGERIAN MEDIUM	34.47	158
INDONESIAN MINAS	35.09	3	NIGERIAN LIGHT	39.32	81
NIGERIAN MEDIUM	33.97	146	NIGERIAN FORCADOS	36.59	147
NIGERIAN LIGHT	38.81	75	VENEZ MED (TJ MED)	33.19	681
NIGERIAN FORCADOS	36.08	135	VEN BACH 17 / 2.4	28.86	372
VENEZ MED (TJ MED)	33.08	668	VEN XHVV BOSCAN 11.2/4	27.49	<10
VEN BACH 17 / 2.4	28.75	365	ANGOLAN	35.40	126
VEN XHVV BOSCAN 11.2/4	27.38	<10	CHINA BLEND	34.47	13
ANGOLAN	34.90	235	COLOMBIAN	35.43	187
COLOMBIAN	35.32	193	ECUADOR	35.39	137
CONGO	33.97	38	EGYPT GHARIB/BAKR	34.23	<19
ECUADOR	35.28	80	GUATEMALA	35.63	12
EGYPT GHARIB/BAKR	33.71	<29	MALAYSIA LABUAN	36.53	9
GUATEMALA	35.51	9	MEXICAN ISTHMUS	35.49	256
MALAYSIA LABUAN	36.41	3	MEXICAN MAYA	28.88	858
MEXICAN ISTHMUS	35.38	280	NORWAY	35.92	97
MEXICAN MAYA	30.73	937	TRINIDAD SWEET LS	37.25	31
NORWAY	35.81	194	TRINIDAD SOUR HS	34.81	31
OMAN	35.36	11	UK	36.32	<500
RUSSIA	35.36	51	ZAIRE	35.40	14
TRINIDAD SWEET LS	37.14	40	ALABAMA HVY	35.36	26
TRINIDAD SOUR HS	34.70	40	ALABAMA LIGHT	36.86	15
UK	35.81	<500	ARKANSAS	32.48	28
ZAIRE	34.90	19	LOUISIANA COND	37.11	95
ALABAMA HVY	35.94	24	LOUISIANA NORTH	36.93	55
ALABAMA LIGHT	37.45	15	LOUISIANA S.MIX/OFFSHORE	35.95	473
ARKANSAS	33.05	27	MISSISSIPPI HEY	36.53	16
LOUISIANA COND	37.68	90	MISSISSIPPI BAX	34.88	34
LOUISIANA NORTH	37.52	52	NEW MEXICO INT	38.66	21
LOUISIANA S.MIX/OFFSHORE	36.53	446	NEW MEXICO SOUR	34.99	42
MISSISSIPPI HEY	37.11	15	TEXAS CONDENSATE	39.74	72
MISSISSIPPI BAX	35.46	32	TEXAS GULF REF	36.10	418
NEW MEXICO INT	39.24	19	TEXAS EAST	36.62	67
NEW MEXICO SOUR	39.25	40	TEXAS HAWKINS	31.16	135
TEXAS CONDENSATE	40.31	68	TEXAS WEST INTERMED	36.74	378
TEXAS GULF REF	36.67	394	TEXAS WEST SOUR	35.09	91
TEXAS EAST	37.19	63	OKLA CEMENT	33.30	24
TEXAS HAWKINS	31.73	127	CALIFORNIA ELK HILLS	34.42	45
TEXAS WEST INTERMED	37.41	356	ALASKAN NORTH SLOPE	34.41	31
TEXAS WEST SOUR	35.57	86	NATURAL GAS (FOE)	18.29	
OKLA CEMENT	33.87	23	NATURAL GASOLINE	34.44	<114
CALIFORNIA ELK HILLS	34.99	42	ISOBUTANE	28.71	<84
ALASKAN NORTH SLOPE	34.46	22	NORMAL BUTANE	26.92	
NATURAL GAS (FOE)	17.24		ETHANOL	21.73	
NATURAL GASOLINE	36.82	<119	METHANOL	26.70	
ISOBUTANE	28.81	<106	MTBE	54.32	
NORMAL BUTANE	26.92		ETBE	54.75	
ETHANOL	27.70		NAPHTHA/REF FEED	34.98	<73.6
METHANOL	25.97		GAS OIL	40.65	<125.9
MTBE	54.10				
ETBE	54.55				
NAPHTHA/REF FEED	37.36	<68.2			
GAS OIL	36.99	<116.7			

Table 19. PADD III process capacity for year 2010 higher ethanol demand conditions

Summer		Winter	
PROCESS	CAPACITY MBS/D	PROCESS	CAPACITY MBS/D
CRUDE DISTILLATION	7545.2	CRUDE DISTILLATION	7545.2
VACUUM DISTILLATION	3400	VACUUM DISTILLATION	3400
FLUID CAT CRACKER	2643.4	FLUID CAT CRACKER	2643.4
HYDROCRACKER-2 STAGE	527	HYDROCRACKER-2 STAGE	527
HYDROCRACKER-LOW CONVER	105	HYDROCRACKER-LOW CONVER	105
RESID HYDROCRACKER	0	RESID HYDROCRACKER	0
COKER-DELAYED	788	COKER-DELAYED	788
VISBREAKER	31.4	VISBREAKER	31.4
SOLVENT DEASPHALTING	174	SOLVENT DEASPHALTING	217.8
LUBE + WAX PLANTS	131.1	LUBE + WAX PLANTS	131.1
NAPHTHA HYDROTREATER	1925	NAPHTHA HYDROTREATER	1925
DISTILLATE HDS	1880.2	DISTILLATE HDS	1880.2
MID DIST DEEP HT	274.771	MID DIST DEEP HT	317.2
FCC FEED HYDROFINER	886.4	FCC FEED HYDROFINER	886.4
VAC RESID DESULF	0	VAC RESID DESULF	0
ATM RESID DESULF	328	ATM RESID DESULF	328
M DIST FURFURAL TRTING	0	M DIST FURFURAL TRTING	0
GAS OIL DEWAXER	0	GAS OIL DEWAXER	0
HP SEMI REGEN REFORMER	649.1	HP SEMI REGEN REFORMER	649.1
LP CYCLIC REFORMER	323	LP CYCLIC REFORMER	323
LP CONTINUOUS REFORMER	890	LP CONTINUOUS REFORMER	890
ALKYLATION PLANT	545.5	ALKYLATION PLANT	545.5
CAT POLYMERIZATION	27.3	CAT POLYMERIZATION	27.3
DIMERSOL	11.5	DIMERSOL	11.5
BUTANE ISOMERIZATION	46.7	BUTANE ISOMERIZATION	46.7
PEN/HEX ISOMERIZATION	186.8	PEN/HEX ISOMERIZATION	186.8
TOTAL RECYCLE ISOM	0	TOTAL RECYCLE ISOM	0
AROMATICS RECOVERY(BTX)	212.7	AROMATICS RECOVERY(BTX)	212.7
MTBE(ETHEROL)	104.1	MTBE(ETHEROL)	104.1
DIPE (MOBIL)	0	DIPE (MOBIL)	0
TH CRACKER-VAC GAS OIL	0	TH CRACKER-VAC GAS OIL	0
NAPHTHA SPLITTER	0	NAPHTHA SPLITTER	0
REFORMATE SPLITTER	0	REFORMATE SPLITTER	0
FCC GASOLINE SPLR	0	FCC GASOLINE SPLR	0
BUTANE SPLITTER	0	BUTANE SPLITTER	0
HYDROGEN PLT,MBPD FOE	68.6	HYDROGEN PLT,MBPD FOE	68.6
SULFUR PLANT,MST/D	14.57	SULFUR PLANT,MST/D	14.57

different climatic markets (NPC 1993). CG baseline properties are from DOE (1994) and API/NPRA (1997). As provided by Section 211 of the CAAA, for gasolines containing 10 percent ethanol, the allowable RVP is one pound per square inch (psi) higher than otherwise established by the CAAA. Tables 20 through 22 summarize the specifications for gasoline emissions performance standards. Specifications for California RFG are shown in Table 23 (CARB).

4.2 REFINERY RAW MATERIALS

Refinery inputs of raw materials are estimated using the *Petroleum Supply Annual* (DOE 1996d; DOE 1998) and the CEC's *Weekly Fuels Watch Report* (CEC 1998b), with extrapolation to year 2010 per growth rates of the *Annual Energy Outlook 1996* (DOE 1996a). The crude oil mix is based on the *Petroleum Supply Annual* (DOE 1996d; DOE 1998), NPC (1993), and the CEC's *Petroleum in California* (CEC 1998a). Swing crudes (without maximum purchase limits) are identified in the tables for regional raw material options.

4.3 PRODUCT AND RAW MATERIAL VALUES

Crude oil and raw material costs are based on the *Annual Energy Outlook 1996* (DOE 1996a), NPC (1993) and *Petroleum Marketing Monthly* (DOE 1995a). Seasonal variations in reference costs for ethanol are based on NPC (1993). Refined product prices are based on the *Annual Energy Outlook 1996* (DOE 1996a), *Petroleum Marketing Monthly* (DOE 1995a), historical price differentials, price ratios, heating values, and estimates reported by NPC (1993). Costs/prices are expressed in 1996 dollars. This study reports the refiner value of ethanol, which is the highest price (after credit for subsidies) that an ethanol producer can command at the refinery/blender gate, as determined by ethanol's value as an ether feedstock or by the refining values of the gasoline blendstocks it displaces.

4.4 TAX INCENTIVES

Federal tax incentives that are targeted for motor fuels containing biomass alcohol are (1) a partial exemption from the federal motor fuel excise taxes that are earmarked for the Highway Trust Fund and (2) a set of credits against income tax. The partial excise tax exemption has been much more important than the income tax credits in terms of the amount of benefits claimed. The size of the partial exemption depends on how much and what type of alcohol is contained in each gallon of fuel. Currently, motor fuels consisting of 10 percent biomass-derived ethanol are exempt from 5.4 cents of the per gallon federal excise tax on gasoline, and other motor fuels that are earmarked for the Highway Trust Fund. The exemption is also available for blends of 5.7 or 7.7 percent ethanol (these blends correspond to the oxygen content standards for gasoline sold in ozone nonattainment and CO nonattainment areas under the CAAA). For these three blends, the exemptions provide a subsidy of 54 cents per gallon of ethanol. Smaller subsidies are provided for blends with ethanol contents which are different from 5.7, 7.7 or 10 percent (GAO 1997).

Ethers of ethanol are eligible for credit against income tax. However, recent experience shows that U.S. refiners do not have enough tax liability to utilize the tax credits (Hodge 1994; *Oxy-Fuels News* 1994).

Table 20. PADD I specifications for emissions performance standards for year 2010

Summer	Winter																					
<p>*PHASE II STANDARDS:</p> <p>*TAP, NOX, VOC ARE EXPRESSED IN UNITS OF MG/MI</p> <p>*CG STANDARD ASSUMES 1989 QUALITY REPORTED IN NPRA (1989) SURVEY</p> <p>*SEE DOE (1994), TABLE 3-2</p> <p>*TAP<93.8; NOX<1436.1; VOC<1679.9</p> <p>*ASSUME PADD I IS 90% CLASS C PER NPC (1993)</p> <p>*BASELINES ARE:</p> <table><tr><td>* REGION</td><td>B</td><td>C</td></tr><tr><td>* VOC</td><td>1466.31</td><td>1399.07</td></tr><tr><td>* TAP</td><td>86.3443</td><td>85.6077</td></tr><tr><td>* NOX</td><td>1340</td><td>1340</td></tr></table> <p>*NOX REDUCTION IS 7.4% = 1240.8</p> <p>*</p> <p>*VOC REDUCTION IS 29% B; 27.4% C</p> <p>*SO VOC = .1(1041.1)+.9(1015.7) = 1018.2 AVERAGING</p> <p>*</p> <p>*TAP REDUCTION IS 21.5% YEAR ROUND.</p> <p>*ASSUME 25% SUMMER REDUCTION WILL SATISFY YEAR ROUND</p> <p>*SO TAP = .1(64.76)+.9(64.21) = 64.3</p>	* REGION	B	C	* VOC	1466.31	1399.07	* TAP	86.3443	85.6077	* NOX	1340	1340	<p>*PHASE II STANDARDS:</p> <p>*TAP, NOX, VOC ARE EXPRESSED IN UNITS OF MG/MI</p> <p>*CG STANDARD ASSUMES 1989 WINTER QUALITY REPORTED BY NIPER 1987-88, DISTRICT 2, WEIGHTED BY OCTANE AND MARKET (DICKSON AND WOODWARD 1988)</p> <p>*PLUS TABLE B10 OF TMC (1993)</p> <p>*TAP<118.1; NOX<1600.8;</p> <p>*ASSUME PADD I IS 90% CLASS C PER NPC (1993)</p> <p>*BASELINES ARE:</p> <table><tr><td>* REGION</td><td>B</td><td>C</td></tr><tr><td>* TAP</td><td>120.5</td><td></td></tr><tr><td>* NOX</td><td>1540.0</td><td></td></tr></table> <p>*NOX REDUCTION IS 1.5% (AVERAGING BASIS) = 1516.9 MG/MI</p> <p>*</p> <p>*TAP REDUCTION IS 21.5% YEAR ROUND.</p> <p>*SUMMER TAP REDUCTION WAS 25%</p> <p>*ACCOUNTING FOR LENGTH OF SEASON (6.5 MONTHS), RFG VOLUMES,</p> <p>*WINTER TAP REDUCTION MUST BE 18.5% = 98.1 MG/MI.</p>	* REGION	B	C	* TAP	120.5		* NOX	1540.0	
* REGION	B	C																				
* VOC	1466.31	1399.07																				
* TAP	86.3443	85.6077																				
* NOX	1340	1340																				
* REGION	B	C																				
* TAP	120.5																					
* NOX	1540.0																					

Table 21. PADD II specifications for emissions performance standards for year 2010

Summer	Winter																		
<p>*PHASE II STANDARDS:</p> <p>*TAP, NOX, VOC ARE EXPRESSED IN UNITS OF MG/MI</p> <p>*CG STANDARD ASSUMES 1990 QUALITY REPORTED IN NPC (1993)</p> <p>*</p> <p>*TAP<88.82; NOX<1398.96; VOC<1681.54</p> <p>*ASSUME PADD II IS 80% CLASS C PER NPC (1993)</p> <p>*BASELINES ARE:</p> <table><tr><td>* REGION</td><td>B</td><td>C</td></tr><tr><td>* VOC</td><td>1466.31</td><td>1399.07</td></tr><tr><td>* TAP</td><td>86.3443</td><td>85.6077</td></tr><tr><td>* NOX</td><td>1340</td><td>1340</td></tr></table> <p>*NOX REDUCTION IS 6.8 PERCENT: 1248.88 MG/MI</p> <p>*</p> <p>*VOC REDUCTION 29% B; 27.4% C;</p> <p>*SO VOC = .2(1041.1)+.8(1015.7) = 1021 AVERAGING</p> <p>*</p> <p>*TAP REDUCTION IS 21.5% YEAR ROUND.</p> <p>*ASSUME 25% SUMMER REDUCTION WILL SATISFY YEAR ROUND</p> <p>*SO TAP = .2(64.76)+.8(64.21) = 64.3</p> <p>*</p>	* REGION	B	C	* VOC	1466.31	1399.07	* TAP	86.3443	85.6077	* NOX	1340	1340	<p>*PHASE II STANDARDS:</p> <p>*TAP, NOX, VOC ARE EXPRESSED IN UNITS OF MG/MI</p> <p>*CG STANDARD ASSUMES WINTER QUALITY IS SAME AS REPORTED BY NIPER</p> <p>* 87-88 (AND 94-95 OLEFINS/AROMATICS, OXYGEN),</p> <p>*DIST 6, GRADE-WEIGHTED (DICKSON AND WOODWARD 1988)</p> <p>*</p> <p>*TAP<108.6; NOX<1529.68;</p> <p>*ASSUME PADD II IS 80% CLASS C PER NPC (1993)</p> <p>*BASELINES ARE:</p> <table><tr><td>* REGION</td><td>B/C</td></tr><tr><td>* TAP</td><td>120.55</td></tr><tr><td>* NOX</td><td>1540.0</td></tr></table> <p>*NOX REDUCTION IS 1.5 PERCENT: 1516.9 MG/MI</p> <p>*</p> <p>*TAP REDUCTION IS 21.5% YEAR ROUND.</p> <p>*SUMMER CASE TAP REDUCTION WAS 26.2%. ACCOUNTING FOR</p> <p>LENGTH OF SEASON AND PRODUCTION VOLUMES, WINTER TAP</p> <p>*REDUCTION IS 17.3% (FOR 21.5% REDUCTION YEAR ROUND).</p> <p>*WINTER TAP TARGET FOR RFG IS 99.69 MG/MI</p> <p>*</p>	* REGION	B/C	* TAP	120.55	* NOX	1540.0
* REGION	B	C																	
* VOC	1466.31	1399.07																	
* TAP	86.3443	85.6077																	
* NOX	1340	1340																	
* REGION	B/C																		
* TAP	120.55																		
* NOX	1540.0																		

Table 22. PADD III specifications for emissions performance standards for year 2010

Summer	Winter																		
<p>*PHASE II STANDARDS:</p> <p>*TAP, NOX, VOC ARE EXPRESSED IN UNITS OF MG/MI</p> <p>*CG STANDARD ASSUMES 1989 QUALITY REPORTED IN NPRA (1989) SURVEY</p> <p>*SEE DOE (1994), TABLE 3-2</p> <p>*TAP<87.27; NOX<1364.52; VOC<1595.79</p> <p>*ASSUME PADD III IS 40% CLASS C PER NPC (1993)</p> <p>*BASELINES ARE:</p> <table><tr><td>* REGION</td><td>B</td><td>C</td></tr><tr><td>* VOC</td><td>1466.31</td><td>1399.07</td></tr><tr><td>* TAP</td><td>86.3443</td><td>85.6077</td></tr><tr><td>* NOX</td><td>1340</td><td>1340</td></tr></table> <p>*NOX REDUCTION IS 6.8 PERCENT: 1248.88 MG/MI</p> <p>*</p> <p>*VOC REDUCTION 29% B; 27.4% C;</p> <p>*SO VOC = .6(1041.1)+.4(1015.7) = 1031 AVERAGING</p> <p>*</p> <p>*TAP REDUCTION IS 21.5% YEAR ROUND.</p> <p>*ASSUME 25% SUMMER REDUCTION WILL SATISFY YEAR ROUND</p> <p>*SO TAP = .6(64.76)+.4(64.21) = 64.5</p> <p>*</p>	* REGION	B	C	* VOC	1466.31	1399.07	* TAP	86.3443	85.6077	* NOX	1340	1340	<p>*PHASE II STANDARDS:</p> <p>*TAP, NOX, VOC ARE EXPRESSED IN UNITS OF MG/MI</p> <p>*CG STANDARD ASSUMES 1989 WINTER QUALITY REPORTED BY</p> <p>*NIPER 1987-88, DISTRICTS 3 AND 12, WEIGHTED BY OCTANE AND MARKET (DICKSON AND WOODWARD 1988)</p> <p>*PLUS TABLE B10 OF TMC (1993)</p> <p>*TAP<87.27; NOX<1364.52; VOC<1595.79</p> <p>*ASSUME PADD III 40% CLASS C PER NPC (1993)</p> <p>*BASELINES ARE:</p> <table><tr><td>* REGION</td><td>B AND C</td></tr><tr><td>* TAP</td><td>110.1</td></tr><tr><td>* NOX</td><td>1475.3</td></tr></table> <p>*NOX REDUCTION IS 1.5 PERCENT (AVERAGING BASIS): 1516.9 MG/MI</p> <p>*</p> <p>*</p> <p>*TAP REDUCTION IS 21.5% YEAR ROUND.</p> <p>*SUMMER TAP REDUCTION WAS 25.4%</p> <p>*ACCOUNTING FOR LENGTH OF SEASON (6.5 MO WINTER), RFG VOLUMES,</p> <p>*WINTER TAP REDUCTION MUST BE 18.1% = 98.7 MG/MI</p> <p>*</p>	* REGION	B AND C	* TAP	110.1	* NOX	1475.3
* REGION	B	C																	
* VOC	1466.31	1399.07																	
* TAP	86.3443	85.6077																	
* NOX	1340	1340																	
* REGION	B AND C																		
* TAP	110.1																		
* NOX	1475.3																		

Table 23. Specifications for Phase 2 California RFG (CARB)

Property	Property limit ^a		
	"Flat"	"Averaging"	"Cap"
RVP (psi, max) ^b	7.0		7.0
Sulfur (wppm, max)	40	30	80
Aromatics (vol%, max)	25	22	30
Benzene (vol%, max)	1.00	0.80	1.20
Olefins (vol%, max)	6.0	4.0	10.0
Oxygen (wt%)	1.8-2.2		1.8-2.2 ^c
T50 (°F)	210	200	220
T90 (°F)	300	290	330

^aFor six of the eight properties, a refiner may choose either the "flat" limit or the "averaging" limit. Averaging is not allowed for RVP or oxygen. The flat limit applies to every batch of finished gasoline. The averaging limit allows specific batches to exceed the flat limit as long as fuel produced over a 180 day period meets the averaging limit and never exceeds the cap limit. The averaging specifications give refiners more blending options and help them control operating costs.

^bStandard for RVP applies in location-specific non-winter months defined in Section 2262.1 of Title 13, California Code of Regulations (CCR, CARB 1996).

^cOxygen content of 2.7 wt% is allowed if the gasoline has been reported as a Predictive Model alternative gasoline formulation (per Section 2265(a) of CCR) or as an alternative gasoline formulation (per Section 2266© of CCR). A maximum oxygen content of 2.2 wt% is premised for this study to avoid Predictive Model violations.

Under an Internal Revenue Service rule, mixtures of gasoline and ETBE qualify for the partial excise tax exemption for gasolines containing ETBE, at oxygen concentrations corresponding to the concentrations for exempt ethanol blends (Lazzari 1995). Claiming the exemption could be complicated by problems related to concentration control, segregation, and tracking problems in the gasoline distribution system. Although the ethanol demand study is subsidy-blind, the study uses the constraints on ethanol blending concentrations imposed by the federal excise tax exemption.

4.5 REFINERY CAPACITY

Refinery capacity is based on in-place capacity and construction reported in the *Petroleum Supply Annual* (DOE 1995b), NPC (1993), NPRA (1991), *Oil & Gas Journal* (1996; Radler 1996), and API/NPRA (1997). Process capacity investment is based on a 15 percent discounted cash flow (DCF) rate of return on investment. Investment premises allow for 20 percent expansion of existing capacity at typical investment costs. Other investment is subject to economies of scale, according to the "six-tenths factor" relationship:

$$\text{Cost}_{\text{New}} = (\text{Capacity}_{\text{New}} / \text{Capacity}_{\text{Typical Size}})^n * \text{Cost}_{\text{Typical Size}}, \text{ with } n \text{ between } 0.6 \text{ and } 0.7$$

According to premise, new capacity is averaged over all refineries in a region. For a fixed value of new capacity (throughput), the average value of capacity falls as the number of refineries increases. The cost equation forces smaller capacity (i.e., less than typical size) to be more costly on a per-unit capacity basis.

It is assumed that refiners will use prohibitively high hurdle rates when considering investment in new technologies because the advertised capabilities in new technologies are not always realized. Therefore, investment is restricted to proven technologies.

4.6 STUDY CASES

4.6.1 Phase 1

Ethanol demand has been estimated in two study Phases. Table 24 shows the Phase 1 plan for 24 study cases plus parametric variations of ethanol value for 8 cases. These cases investigate refiner/blender demand for ethanol for reference conditions and for higher ethanol demand conditions, with variations in world oil price, cost of competing oxygenate, and ethanol value. There are also several sensitivity cases in the study design. The ORNL-RYM analysis accounts for economic and specification-based factors which influence ethanol demand for gasoline production and finishing, including:

1. oxygenation requirements for RFG and winter gasolines for CO nonattainment areas,
2. octane requirements for all gasolines,

Table 24. Phase I studies of demand for ethanol in U.S. gasoline production and finishing in year 2010

Factor	Reference conditions				Higher ethanol demand case			
PADD	II	II	III	III	II	II	III	III
Season	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
RFG share ^a (percent)	Current (12)	Current (13)	Current (18)	Current (18)	Current (12)	Current (13)	Current (18)	Current (18)
World oil price ^b (per barrel)	Reference (\$24.77)	Reference (\$24.77)	Reference (\$24.77)	Reference (\$24.77)	High (\$34.08)	High (\$34.08)	High (\$34.08)	High (\$34.08)
MTBE cost ^c	Function of reference case outlook	Function of reference case outlook	Function of reference case outlook	Function of reference case outlook	Function of high price case outlook	Function of high price case outlook	Function of high price case outlook	Function of high price case outlook
Ethanol value	Vary	Vary	Vary	Vary	Vary	Vary	Vary	Vary
Model runs	<p>For each of the 8 sets of conditions:</p> <p>1 Base Case. Summer refinery capacity will be current + construction + investment under the set of case conditions. Winter refinery capacity will be summer capacity + investment under the set of case conditions.</p> <p>1 Parametric Variation of Ethanol Value, executed with Base Case data. Parametric cases will give modeled refinery's ethanol demand curve over full range of ethanol value. Blending properties and investment costing must be held constant over full range of ethanol value.</p> <p>2 Cases at Different Ethanol Values. For greater accuracy compared to the parametric cases: blending properties and investment costing will be adjusted as needed.</p> <p>For PADD III summer, high ethanol demand conditions:</p> <p>1 Parametric Variation of MTBE Cost.</p> <p>1 Sensitivity Case allowing investment in promising technologies.</p>							

^aCurrent RFG share based on *Motor Gasoline Watch* (DOE 1997) and *Petroleum Supply Annual* (DOE 1996d; DOE 1998). Full opt-in share based on *U.S. Petroleum Refining* (NPC 1993).

^bWorld oil price from *Annual Energy Outlook* (DOE 1996a).

^cMTBE costs based on MATHPRO INC (1995).

3. refinery operations, investment, and associated costs, and
4. gasoline emissions limits for VOCs, TAPs, and NOx.

4.6.2 Phase 2

Given Phase 1 results, Phase 2 study cases, shown in Table 25, are based on the following considerations:

National ethanol demand can be estimated by scaling up the Phase 1 results for PADDs II and III (see Appendix B). However, greater reliability and analytical consistency can be realized with refinery model analysis for additional U.S. regions. For reference case demand conditions, summer and winter cases have been examined for the additional regions of the East Coast (PADD I) and California (PADD VC).

Parametrically generated demand curves are generally in good agreement with results of individual case studies in Phase 1. Therefore, for each set of factor conditions in Phase 2, only one case has been examined in detail, with parametric generation of the ethanol demand curve.

While the maximum allowable oxygen content is currently 3.5 wt percent for ethanol blends, it has been reported that modern vehicles can generally perform adequately with oxygen levels of up to 6 wt percent (EEA). Therefore, ethanol demand has been estimated in a Phase 2 case with a maximum allowable oxygen content of 6 wt percent (about 17 volume percent ethanol).

EPA believes that a reduction of sulfur in gasoline may be required to enable use of advanced vehicle pollution control technologies. Ethanol may have increased value because of its sulfur dilution effect and high octane. In Phase 2, summer ethanol demand has been estimated for PADD II, with production of 100 percent LSG at 100 parts per million (ppm) sulfur. PADD II has been selected for this case study because desulfurization requirements are driven primarily by the size of the CG pool, and ethanol is a more attractive blendstock for summer CG relative to RFG. PADD II has a very high CG production share and is the most active ethanol-blending region.

Changes in gasoline specifications and blending property values could result in higher ethanol demand. In separate Phase 2 cases, ethanol demand has been estimated for:

A VOC waiver for RFG. VOC emissions make summer RFG difficult to produce with high vapor pressure oxygenates like ethanol, and proponents of ethanol use in RFG have sought relief from the current VOC (RVP-related) specification. The premised VOC specification for ethanol-based RFG allows a 5 percent increase in VOC emissions. This VOC waiver premise is equivalent to a 0.5-0.7 psi RVP allowance for ethanol-based RFG. This waiver decreases the VOC advantage of MTBE-based RFG.

A toxicity correction for MTBE. The EPA Complex Model for emissions of pollutants does not account for TAP due to evaporative and exhaust emissions of MTBE. If TAP due to MTBE were accounted for, ethanol could have an additional advantage in gasoline blending. Based on

Table 25. Phase 2 studies of demand for ethanol in U.S. gasoline production and finishing

Factor	Reference conditions											
	I	I	II	II	II	II	II	II	III	III	VC	VC
PADD	Sum	Win	Sum	Win	Sum	Sum	Sum	Sum	Sum	Sum	Sum	Win
Ethanol in gasoline, percent	≤10	≤10	17	17	≤10	≤10	≤10	≤10	≤10	≤10	≤10	≤10
LSG share, percent	0	0	0	0	100	0	0	0	0	0	0	0
VOC Waiver						Yes						
Toxicity correction							Yes					
Octane Increase								Yes				
Ratio-constrained Model									Yes			
Parametric variation of ethanol value									No			
Latest outlook for energy markets										Yes		
Other factors	RFG share ^a : current World oil price ^b : reference conditions MTBE cost ^c : function of reference case Ethanol value: vary											

^aCurrent RFG share based on *Motor Gasoline Watch* (DOE 1997), *Petroleum Supply Annual* (DOE 1996d; DOE 1998), and the California Energy Commission's *Weekly Fuels Watch Report* (CEC 1998b). Full opt-in share based on *U.S. Petroleum Refining* (NPC 1993).

^bWorld oil price from *Annual Energy Outlook* (DOE 1996a).

^cMTBE costs based on MATHPRO INC (1995).

EPA guidance, TAP specifications have been changed to remove the advantage in the TAP model for MTBE-containing RFG.

An increase in octane specifications. The likelihood of an increase in octane specification is uncertain, but nonetheless plausible. For example, higher compression ratios may be needed to achieve higher efficiencies. With higher compression ratios, higher octane gasolines might be needed to inhibit preignition. The ethanol demand impact of a 1 number increase in Research and Motor octane specifications has been estimated.

Most case studies have been performed with the Ratio-free version of ORNL-RYM. The Ratio-constrained version of ORNL-RYM imposes restrictions on hydrocarbon processing within the model, which could make ethanol a more attractive blendstock than in the Ratio-free version. A Phase 2 case has examined the effect of the Ratio-constrained model on the ethanol demand estimate.

Refinery modeling premises for Phase 2 cases should be consistent with Phase 1. Therefore, premises for most additional cases in Phase 2 are based on the *Scenario Document for Estimation of Ethanol Demand in Gasoline Production* (Hadder 1997), which includes use of data reported in EIA's *Annual Energy Outlook 1996* (DOE 1996a). However, to evaluate the impact of changes in the outlook, a sensitivity case has been examined using data from the more recently published *Annual Energy Outlook 1998* (DOE 1997a).

5. THE DEMAND FOR ETHANOL USED IN GASOLINE PRODUCTION AND FINISHING FOR REFERENCE CONDITIONS IN YEAR 2010

5.1 PADD I, SUMMER

PADD I is a 17 state area on the U.S. East Coast. This study assumes that there are 17 PADD I refineries, which produce 11 percent of all gasoline manufactured in the U.S.

Figure 1 shows the ORNL-RYM estimate of the demand curve for ethanol used in PADD I gasoline production and finishing in year 2010, for summer reference conditions. Demand curves are produced with a parametric linear programming feature that recomputes a solution with incremental increases in the refiner value of ethanol. With the parametric technique, ethanol blending properties, pollutant emission blending properties, and costs per unit of refinery process investment must be held constant. Because these factors are not actually constant, individual case studies were examined for other regions to confirm whether the demand curves are reasonable. Individual case study results show good agreement with the parametrically generated demand curve.

Ethanol demand is a function of the refiner value of ethanol. At a value of \$1.00 per gallon, ethanol demand is 0.2 BGY. Demand is 1 BGY at refiner values below \$0.60 per gallon, and the ethanol concentration in the total gasoline pool is 8 volume percent. Figure 1 shows that ethanol demand is dominated by ethanol blended to CG and by ethanol used in production of ETBE. Key factors in the ethanol demand pattern for PADD I are:

- (1) limits on VOCs, for which RVP is the major determinant, make summer RFG difficult to produce with high-RVP oxygenates like ethanol,
- (2) ethanol's attractiveness in CG is enhanced by the 1 psi RVP waiver for 10 percent ethanol blends, and
- (3) with a large RFG production share (61 percent of total gasoline), a substantial volume of ethanol is used to produce low-RVP ETBE, which displaces MTBE as ethanol values fall.

Figure 2 illustrates how ethanol can be an attractive blendstock in optimized blending when the value of ethanol (solid line) is higher than the value of gasoline (lower chained line). Gasoline is a mixture of blendstocks, and the higher valued blendstocks (such as alkylate, represented by the upper dashed line) can be selectively displaced by ethanol. When energy content, blending properties, and revenue effects are taken into account, ethanol at \$1.00 per gallon (its highest value in the figure) could begin to displace alkylate at \$1.15 per gallon, in CG that is valued at \$0.92 per gallon.

Figure 3 decomposes oxygenate use by oxygenate type and gasoline type. The right side of the ethanol demand curve is inelastic because gasolines are approaching the maximum allowable oxygen limits. Figure 3 also shows how the oxygenate preference in RFG switches from MTBE to ETBE as the refiner value of ethanol falls.

Fig. 1. Ethanol used in PADD I gasoline production and finishing
Year 2010 summer - reference conditions

Fig. 2. Relative value of ethanol in PADD I gasoline production and finishing
Year 2010 summer - reference conditions

Fig. 3. Oxygenates used in PADD I gasoline production and finishing
Year 2010 summer - reference conditions

A complex change in the pattern of oxygenate use occurs as the value of ethanol rises from \$0.90 to \$1.00 per gallon. At \$0.93 per gallon, ethanol becomes less attractive for blending to CG, and MTBE and other hydrocarbons begin to displace ethanol in CG. In the range of \$0.93 to \$0.95 per gallon of ethanol, MTBE is drawn from RFG into CG, and ETBE use temporarily increases in RFG (a higher value product than CG) to compensate for MTBE shifted to CG. Above \$0.95 per gallon of ethanol, MTBE increasingly displaces ETBE in RFG. A second look at Figure 1 shows that, although there is a slight reversal in a component (ETBE) of demand for ethanol, the demand curve for total ethanol has no reversals as the value of ethanol rises.

5.2 PADD I, WINTER AND ANNUALIZED

Figure 4 shows the demand curve for ethanol used in PADD I gasoline production for winter reference conditions. At a refiner value of \$1.00 per gallon, ethanol demand is 0.7 BGY. At refiner values below \$0.60 per gallon, ethanol demand is 1 BGY, and ethanol concentration in the total gasoline pool is 8 volume percent. Because RVP is a less important factor in winter, ethanol increases and ETBE decreases in RFG blending.

It is assumed that the summer season is 5.5 months long and the winter season is 6.5 months long. With account for different season lengths and different gasoline production within seasons, Figure 5 shows the annualized demand for ethanol used in PADD I gasoline production and finishing, for reference conditions. At a refiner value of \$1.00 per gallon, ethanol demand is 0.7 BGY. At \$0.60 per gallon, ethanol demand is 1 BGY.

5.3 PADD II, SUMMER

PADD II is a 15 state area in the U.S. Midwest. This study assumes that PADD II has 35 refineries which produce 24 percent of all gasoline manufactured in the U.S.

Figure 6 shows the ORNL-RYM estimate of the demand curve for ethanol used in PADD II gasoline production and finishing in year 2010, for summer reference conditions. At a refiner value of \$1.00 per gallon, ethanol demand is 0.7 BGY. Ethanol demand is 2.8 BGY at refiner values below \$0.60 per gallon, and the ethanol concentration in the total gasoline pool is 9 volume percent. Figure 6 shows good agreement between the demand estimates of individual case studies and the parametrically generated demand curves. Individual case studies are examined at a single ethanol value, and the associated ethanol demand is represented by a symbol in the figure.

Figure 6 shows that ethanol demand is dominated by CG. Three factors contribute to the overwhelming use of ethanol in CG.

- (1) The premised RFG share of gasoline production is low (12 percent, corresponding to the current share). It will be shown in Section 7.1 that a higher percentage of RFG would decrease the total demand for ethanol.
- (2) Because of limits on VOCs, for which RVP is the major determinant, summer RFG is difficult to produce with high-RVP oxygenates like ethanol.

Fig. 4. Ethanol used in PADD I gasoline production and finishing
Year 2010 winter - reference conditions

Fig. 5. Annualized ethanol used in PADD I gasoline production and finishing in year 2010

**Fig. 6 Ethanol used in PADD II gasoline production and finishing
Year 2010 summer - reference conditions**

- (3) Ethanol's attractiveness in CG is enhanced by the 1 psi RVP waiver for 10 percent ethanol blends.

Figure 7 decomposes oxygenate use by oxygenate type and gasoline type. The right side of the ethanol demand curve is inelastic because CG has become "saturated" with ethanol, given the study premises. Figure 7 also shows how the oxygenate preference in RFG switches from MTBE to ETBE as the refiner value of ethanol falls.

5.4 PADD II, WINTER AND ANNUALIZED

Figure 8 shows the demand curve for ethanol used in PADD II gasoline production for winter reference conditions. At a refiner value of \$1.00 per gallon, ethanol demand is 0.2 BGY. At a refiner value of \$0.60 per barrel, ethanol demand is 2.0 BGY, and ethanol concentration in the total gasoline pool is 7 volume percent. RVP-related advantages disappear for winter CG, and there is increased use of ethanol in RFG. However, total ethanol used in RFG remains low relative to ethanol used in CG because of the premised RFG production share.

With account for different season lengths and different gasoline production within seasons, the solid line of Figure 9 shows the annualized demand for ethanol used in PADD II gasoline production and finishing, for reference conditions. At a refiner value of \$1.00 per gallon, ethanol demand is 0.4 BGY. At \$0.60 per gallon, ethanol demand is slightly higher than 2.3 BGY.

5.5 PADD III, SUMMER

PADD III is a region consisting of six states, most of which are located on the Gulf Coast. This study assumes that there are 65 PADD III refineries, which produce 45 percent of all gasoline manufactured in the U.S.

Figure 10 shows the ORNL-RYM estimate of the demand curve for ethanol used in PADD III gasoline production and finishing in year 2010, for summer reference conditions. At a refiner value of \$1.00 per gallon, ethanol demand is 0.7 BGY. Ethanol demand is 5.2 BGY at refiner values below \$0.60 per gallon, and the ethanol concentration in the total gasoline pool is 9 volume percent. Figure 10 shows that ethanol demand is dominated by CG. The factors which favor the use of ethanol in CG include low RFG share (18 percent); restrictive VOC requirement for RFG; and the 1 psi RVP waiver for 10 percent ethanol.

Figure 11 decomposes oxygenate use by oxygenate type and gasoline type. The right side of the ethanol demand curve is inelastic because CG has become saturated with ethanol, given the study premises. Figure 11 also shows how the oxygenate preference in RFG switches from MTBE to ETBE as the refiner value of ethanol falls.

Fig. 7. Oxygenates used in PADD II gasoline production and finishing
Year 2010 summer - reference conditions

Fig. 8. Ethanol used in PADD II gasoline production and finishing
Year 2010 winter - reference conditions

Fig. 9. Annualized ethanol used in PADD II gasoline production and finishing in year 2010

Fig. 10. Ethanol used in PADD III gasoline production and finishing
Year 2010 summer - reference conditions

Fig. 11. Oxygenates used in PADD III gasoline production and finishing
Year 2010 summer - reference conditions

5.6 PADD III, WINTER AND ANNUALIZED

Figure 12 shows the demand curve for ethanol used in PADD III gasoline production for winter reference conditions. At a refiner value of \$1.00 per gallon, ethanol demand is 0.9 BGY. At a refiner value of \$0.60 per gallon, ethanol demand is 3.3 BGY, and the ethanol concentration in the total gasoline pool is 6 volume percent. RVP-related advantages disappear for winter CG, and there is a significant increase in use of ethanol in RFG. However, ethanol used in RFG remains low relative to ethanol used in CG because of the premised RFG production share.

With account for different season lengths and different gasoline production within seasons, the solid line of Figure 13 shows the annualized demand for ethanol used in PADD III gasoline production and finishing, for reference conditions. At a refiner value of \$1.00 per gallon, ethanol demand is 0.8 BGY. At \$0.60 per gallon, ethanol demand is 4.2 BGY.

5.7 CALIFORNIA, SUMMER

California has 22 refineries which produce 13 percent of all gasoline manufactured in the U.S.

Figure 14 shows the ORNL-RYM estimate of the demand curve for ethanol used in California gasoline production and finishing in year 2010, for summer reference conditions. At a refiner value of \$1.00 per gallon, ethanol demand is 0.1 BGY. Ethanol demand is 1.05 BGY at refiner values below \$0.60 per gallon, and the ethanol concentration in the total gasoline pool is 6 volume percent. Figure 14 shows that ethanol demand is dominated by ETBE and ethanol blended to RFG. Relatively less ethanol is used in CG because the RFG production share is very high (86 percent).

Figure 15 decomposes oxygenate use by oxygenate type and gasoline type. The right sides of the ethanol and ETBE demand curves are inelastic because gasolines cannot accept more oxygen, given the study premises. Figure 15 also shows how the oxygenate preference in RFG switches from MTBE to ETBE as the refiner value of ethanol falls.

5.8 CALIFORNIA, WINTER AND ANNUALIZED

Figure 16 shows the demand curve for ethanol used in California gasoline production for winter reference conditions. At a refiner value of \$1.00 per gallon, ethanol demand is 0.6 BGY. At a refiner value of \$0.60 per gallon, ethanol demand is 0.83 BGY, and the ethanol concentration in the total gasoline pool is 6 volume percent. Because of the high allowable RVP in winter, there is a significant increase in use of ethanol in RFG, as ethanol displaces ETBE.

With account for different season lengths and different gasoline production within seasons, Figure 17 shows the annualized demand for ethanol used in California gasoline production and finishing, for reference conditions. At a refiner value of \$1.00 per gallon, ethanol demand is 0.4 BGY. At \$0.60 per gallon, ethanol demand is 0.93 BGY.

Fig. 12. Ethanol used in PADD III gasoline production and finishing
Year 2010 winter - reference conditions

Fig. 13. Annualized ethanol used in PADD III gasoline production and finishing in year 2010

Fig. 14. Ethanol used in California gasoline production and finishing
Year 2010 summer - reference conditions

Fig. 15. Oxygenates used in California gasoline production and finishing
Year 2010 summer - reference conditions

Fig. 16. Ethanol used in California gasoline production and finishing
Year 2010 winter - reference conditions

Fig. 17. Annualized ethanol used in California gasoline production and finishing in year 2010

5.9 ESTIMATED U.S. DEMAND FOR ETHANOL IN GASOLINE PRODUCTION AND FINISHING

In Figure 18, the annualized ethanol demand estimates for PADDs I, II, III, and California have been scaled up to an estimate of demand for the total U.S. gasoline production system. The scaling factors (discussed in Appendix B) account for differences in regional gasoline production, by type of gasoline, and for differences in regional and national RFG production share. It is assumed that the national RFG production share is 30 percent. For reference conditions, the solid line in Figure 18 shows that ethanol demand is 2 BGY at a refiner value of \$1.00 per gallon of ethanol. Demand is 9 BGY at a refiner value of \$0.60 per gallon of ethanol.

Fig. 18. Ethanol demand range for U.S. gasoline production and finishing in year 2010

6. THE DEMAND FOR ETHANOL USED IN GASOLINE PRODUCTION AND FINISHING FOR HIGHER ETHANOL DEMAND CONDITIONS IN YEAR 2010

6.1 PADD II, SUMMER

Higher ethanol demand is promoted by high economic growth, with higher demand for petroleum products; higher oil prices; and higher cost of oxygenates that compete with ethanol.

Figure 19 shows the ORNL-RYM estimate of the demand curve for ethanol used in PADD II gasoline production and finishing in summer of year 2010, for higher ethanol demand conditions. At a refiner value of \$1.00 per gallon, ethanol demand is 2.6 BGY. Ethanol demand is 2.9 BGY at refiner values of ethanol below \$0.60 per gallon, and ethanol concentration in the total gasoline pool is 9.5 volume percent. Figure 19 shows that ethanol demand is dominated by CG. The factors which favor the use of ethanol in CG include low RFG share (12 percent); restrictive VOC requirement for RFG; and the 1 psi RVP waiver for 10 percent ethanol.

Figure 20 decomposes oxygenate use by oxygenate type and gasoline type. The right side of the ethanol demand curve is inelastic because CG has become saturated with ethanol, given the study premises. Figure 20 also shows how the oxygenate preference in RFG switches from MTBE to ETBE as the refiner value of ethanol falls.

6.2 PADD II, WINTER AND ANNUALIZED

Figure 21 shows the demand curve for ethanol used in PADD II gasoline production for higher ethanol demand conditions in winter. At a refiner value of \$1.00 per gallon, ethanol demand is 1.8 BGY. At a refiner value of ethanol of about \$0.60 per gallon, ethanol demand is 2.6 BGY, and ethanol concentration in the total gasoline pool is 9 volume percent. RVP-related advantages disappear for winter CG, and there is some increase in use of ethanol in RFG over part of the range of refiner values. However, ethanol used in RFG remains low relative to ethanol used in CG because of the premised RFG production share.

With account for different season lengths and different gasoline production within seasons, the broken line of Figure 9 shows the annualized demand for ethanol used in PADD II gasoline production and finishing, for higher ethanol demand conditions. At a refiner value of \$1.00 per gallon, ethanol demand is 2.2 BGY. At \$0.60 per gallon, ethanol demand is nearly 2.8 BGY. Figure 9 shows that there is a very substantial shift in the ethanol demand curve for reference conditions versus higher ethanol demand conditions.

6.3 PADD III, SUMMER

Figure 22 shows the ORNL-RYM estimate of the demand curve for ethanol used in PADD III gasoline production and finishing in year 2010, for higher ethanol demand conditions. At a refiner value of \$1.00

Fig. 19 Ethanol used in PADD II gasoline production and finishing
Year 2010 summer - higher ethanol demand

Fig. 20. Oxygenates used in PADD II gasoline production and finishing
Year 2010 summer - higher ethanol demand

Fig. 21. Ethanol used in PADD II gasoline production and finishing
Year 2010 winter - higher ethanol demand

Fig. 22. Ethanol used in PADD III gasoline production and finishing
Year 2010 summer - higher ethanol demand

per gallon, ethanol demand is 3.0 BGY. Ethanol demand is 5.3 BGY at refiner values of ethanol below \$0.60 per gallon, and ethanol concentration in the total gasoline pool is 9 volume percent. Figure 22 shows that ethanol demand is dominated by CG. The factors which favor the use of ethanol in CG include low RFG share (18 percent); restrictive VOC requirement for RFG; and the 1 psi RVP waiver for 10 percent ethanol.

Figure 23 decomposes oxygenate use by oxygenate type and gasoline type. The right side of the ethanol demand curve is inelastic because CG has become saturated with ethanol, given the study premises. Figure 23 also shows how the oxygenate preference in RFG switches from MTBE to ETBE as the value of ethanol falls.

6.4 PADD III, WINTER AND ANNUALIZED

Figure 24 shows the demand curve for ethanol used in PADD III gasoline production for higher ethanol demand conditions in the winter. At a refiner value of \$1.00 per gallon, ethanol demand is 2.2 BGY. At a refiner value of \$0.60 per gallon, ethanol demand is 4.4 BGY, and the ethanol concentration in the total gasoline pool is 8 volume percent. RVP-related advantages disappear for winter CG, and there is a significant increase in use of ethanol in RFG. However, ethanol used in RFG remains low relative to ethanol used in CG because of the premised RFG production share.

With account for different season lengths and different gasoline production within seasons, the broken line of Figure 13 shows the annualized demand for ethanol used in PADD III gasoline production and finishing, for higher ethanol demand conditions. At a refiner value of \$1.00 per gallon, ethanol demand is 2.5 BGY. At \$0.60 per gallon, ethanol demand is 4.8 BGY. Figure 13 shows that there is a very substantial shift in the ethanol demand curve for reference conditions versus higher ethanol demand conditions.

6.5 ESTIMATED U.S. DEMAND FOR ETHANOL IN GASOLINE PRODUCTION AND FINISHING

In Figure 18, the annualized ethanol demand estimates for PADDs II and III have been scaled up to an estimate of demand for the total U.S. gasoline production system for higher ethanol demand conditions. The scaling factors (discussed in Appendix B) account for differences in regional gasoline production, by type of gasoline, and for differences in regional and national RFG production share. It is assumed that the national RFG production share is 30 percent. For higher ethanol demand conditions, the broken line in Figure 18 shows that ethanol demand is 6.5 BGY at \$1.00 per gallon of ethanol. At \$0.60 per gallon, ethanol demand is 10.6 BGY. Ethanol demand is substantially higher compared to reference conditions.

6.6 MULTIYEAR FORECASTS OF ETHANOL DEMAND

Multiyear forecasts of ethanol supply and demand are required to examine tax incentive schedules to help initiate a commercial cellulosic ethanol industry (TMS 1997). For the component of demand due to ethanol blending in gasoline, the refinery model's ethanol demand curve for reference conditions in year

Fig. 23. Oxygenates used in PADD III gasoline production and finishing
Year 2010 summer - higher ethanol demand

Fig. 24. Ethanol used in PADD III gasoline production and finishing
Year 2010 winter - higher ethanol demand

2010 has been extrapolated to demand curves for five-year intervals between years 2000 and 2025, using extrapolation factors for petroleum prices and gasoline supply derived from the *Annual Energy Outlook* (DOE 1996b). Extrapolation premises are discussed in Appendix C.

Multi-year forecasts are shown in Figure 25. A most important factor in ethanol demand is the premised value of gasoline. When demand is expressed in terms of the difference in gasoline and ethanol values, as shown in Figure 26, the ORNL-RYM ethanol demand estimate for PADD II (backcast to year 1997) matches very closely the actual demand for ethanol in PADD II in the summer of 1997. It is important to keep in mind that backcasting invites errors because there are differences in the premises for year 2010 versus actual conditions in 1997. Furthermore, there is uncertainty about agreement between backcast and actual ethanol demand because the demand curve is very elastic, and Midwestern state incentives for ethanol may not be accurately represented.

Fig. 25. Ethanol demand for U.S. gasoline production and finishing in years 2000 to 2025 - reference conditions

Fig. 26. Ethanol demand sensitivity to relative value of gasoline in PADD II - model backcast to summer 1997

Actual summer 1997 ethanol demand = 1.1BGY at value difference $-\$0.036$. Model backcast demand = 1.2 BGY at $-\$0.036$ per gallon. Caution: backcasting invites errors due to premise differences; elasticity of curve; and inaccurate representation of state incentives.

7. ETHANOL DEMAND SENSITIVITIES

7.1 RFG PRODUCTION SHARE

In development of study premises, it was anticipated that the mandated minimum oxygen levels for RFG would promote the use of ethanol and its ethers. The original study design assumed that ethanol demand would be higher with full opt-in for RFG, compared to current RFG use. However, exploratory ORNL-RYM runs showed that ethanol demand was lower with a higher RFG share of total gasoline production. Model runs were examined for current RFG share (18 percent) and full opt-in RFG share (about 62 percent) for PADD III, using all other premises for the higher ethanol demand conditions.

The RFG share effect on ethanol demand depends on season. Figure 27 shows that a higher RFG share in the summer substantially reduces ethanol demand. Because of limits on VOCs, for which the major determinant is RVP, summer RFG is more difficult to produce with high-RVP oxygenates like ethanol. Ethanol's attractiveness in CG is enhanced by the 1 psi RVP waiver for 10 percent ethanol blends. While ETBE has a low RVP blending value, ETBE is more costly to produce or purchase over part of the demand curve, compared to MTBE. Furthermore, the opportunity to use ETBE in ether-containing gasolines is restricted by the premised maximum allowable oxygen content of 2.7 wt percent, compared to 3.5 wt percent for ethanol-containing gasolines.

In the winter, allowable RVP is much higher, and there are no limits for VOC emissions. RVP-related advantages disappear for winter CG. Winter RFG becomes more attractive (versus CG) for ethanol blending for a combination of reasons, including the higher price for RFG. Figure 28 shows that the use of ethanol is promoted by higher production of winter RFG and oxygenated gasoline for CO nonattainment areas.

Ethanol blending in summer CG is greater than ethanol blending in winter RFG and oxygenated gasoline for CO nonattainment areas. Figure 29 shows that, even with a shorter summer season, the annualized ethanol demand is greater with a program that has a higher use of summer CG (a lower RFG share). RFG opt-in programs cannot be varied seasonally. States cannot opt-in for winter RFG and opt-out for summer. Therefore, for higher ethanol demand conditions, the study premises were changed to a low RFG production share (current share).

7.2 INVESTMENT

It is assumed that refiners will use prohibitively high hurdle rates when considering investment in new technologies, because the advertised capabilities in new technologies are not always realized. Therefore, investment is restricted to proven technologies in the study cases. A sensitivity case has been examined in which investment is opened to additional process technologies for PADD III for summer higher ethanol demand conditions. The additional processes, their purpose, and potential importance are shown in Table 26.

Table 27 shows that, when investment options are opened, there is a substantial increase in the process for isomerization of butane-1 to butane-2, and butadiene removal. This process addition reduces

Fig. 27. Summer ethanol demand versus RFG share for PADD III gasoline production and finishing
Year 2010 summer - higher ethanol demand

Fig. 28. Winter ethanol demand versus RFG share for PADD III gasoline production and finishing
Year 2010 winter - higher ethanol demand

Fig. 29. Annual ethanol demand versus RFG share for PADD III gasoline production and finishing
Year 2010 - higher ethanol demand

Table 26. Additional process options for PADD III investment sensitivity study
(higher ethanol demand conditions, summer year 2010)

Process	Purpose	Potential importance
Alkylation of benzene	Reduction of benzene, production of alkylate	Reduction of TAP emissions in gasoline; CAAA compliance
OCTGAIN	Reduction of sulfur in heavy FCC naphtha, with minimal octane loss	Reduction of NOx and TAP emissions in gasoline; CAAA compliance
Hydrogenation of normal pentenes and hexenes	Reduction of olefins	Reduction of NOx emissions in gasoline; CAAA compliance
Naphtha hydrocracking	Production of C4s from naphthas	Production of oxygenates for gasoline; CAAA compliance
Thermal cracking (gas) Thermal cracking (naphtha)	Production of light olefins	Production of oxygenates for gasoline; CAAA compliance
Cryogenic fractionation/ Dimerization of ethylene	Recovery of ethylene/ Production of butylene	Production of oxygenates for gasoline; CAAA compliance
C2-C5 dehydrogenation	Production of light olefins	Production of oxygenates for gasoline; CAAA compliance
Isomerization of butane-1 to butane-2, and butadiene removal	Improve alkylate octane	Gasoline production
Cyclar	Aromatization of liquefied petroleum gas with fractionation of benzene	Gasoline production from alternative raw material

Table 27. Process capacity additions ^a for PADD III investment sensitivity study (higher ethanol demand conditions, summer year 2010)		
Process ^b	Investment restricted: proven and widely used technologies	Investment opened to additional process technologies
Solvent deasphalting	137	134
Lube and wax units	6	6
Middle distillate deep hydrotreating	82	82
Hydrogen production, fuel oil equivalent (FOE)	9	8
Isomerization of butane-1 to butane-2, and butadiene removal		128
Million dollars	2425	2457
^a Thousand barrels per day		
^b Investment decisions are based on a 15% DCF return on investment.		

operation costs at the alkylation unit and increases the octane of alkylate. In response to the octane benefit for alkylate, there is a reduction in octane provided by reformate, FCC naphtha, and hydrocrackate. As shown in Table 28, there is reduced hydrogen generation by the reformers, but this reduction is more than offset by reduced demand for hydrogen for FCC feed hydrofining and hydrocracking. In fact, there is a reduction in investment in hydrogen plant. With reduced FCC hydrofining, there is a small increase in gasoline pool sulfur (+ 5 ppm or 1.8 percent increase).

Opening investment options has negligible effect on ethanol demand (up 0.01 BGY or 0.2 percent). Refiners realize a cost savings of 0.07 cents per gallon of gasoline.

Table 28. Hydrogen balance for PADD III investment sensitivity study
(higher ethanol demand conditions, summer year 2010)

Process	Fuel oil equivalent barrels of hydrogen per day (minus sign indicates consumption)	
	Investment restricted: proven technologies	Investment opened to additional process technologies
Naphtha hydrotreating	-2885	-2901
Distillate desulfurization	-24695	-24740
Resid desulfurization	-8016	-8016
FCC feed hydrofining	-14470	-13748
Gas oil hydrocracking	-57452	-56781
Reforming	+58564	+58165
C4 isomerization	-83	-83
C5/C6 isomerization	-47	-47
Ether production	-629	-629
Hydrogen production	+70211	+69222
Hydrogen to fuel and losses	-20497	-20358
Isomerization of butane-1 to butane-2, and butadiene removal	0	-83

7.3 MTBE COST

Previous figures have shown the shift in preference from MTBE to ETBE, as the refiner value of ethanol decreases. The linear programming parametric feature has been used to estimate ethanol demand as a function of the difference in refiner values for MTBE and ethanol for PADD III higher ethanol demand conditions in the summer of year 2010. Figure 30 shows how ethanol demand increases with increases in the value of MTBE relative to ethanol.

**Fig. 30. Ethanol demand sensitivity to MTBE value for PADD III gasoline production and finishing
Year 2010 summer - higher ethanol demand**

With a \$0.04 per gallon difference in value, MTBE provides virtually all gasoline oxygenation. The gasoline pool consists of 14.8 percent MTBE, and the ether-based oxygen content for the gasoline pool is at the maximum allowable 2.7 percent.

If the value difference increases to \$0.19 per gallon, then the gasoline pool consists of 7.7 percent ethanol (for a gasoline pool average of 2.2 percent oxygen from ethanol) and 2.3 percent MTBE (for a gasoline pool average of 0.4 percent oxygen from MTBE).

For comparison with markets of summer 1997, fuel ethanol demand was somewhat above 1 BGY, and the spot price difference in MTBE and ethanol ranged from \$0.13 per gallon to \$0.23 per gallon, with an average difference of \$0.19 per gallon (*Oxy-Fuel News* 1998).

7.4 INCREASE IN ALLOWABLE OXYGEN

While the maximum allowable oxygen content is currently 3.5 wt percent for ethanol blends, it has been reported that modern vehicles can perform adequately with oxygen levels of up to 6 wt percent (EEA), and EPA has investigated vehicle exhaust emissions and fuel economy with gasoline blends containing more than 6 wt percent oxygen (Guerrheri et al. 1995). To evaluate its sensitivity to the oxygen specification for gasoline, ethanol demand in PADD II has been estimated in summer and winter cases with a maximum allowable oxygen content of 6 wt percent (about 17 volume percent ethanol). The RVP blending value of ethanol decreases as the amount of ethanol in gasoline increases, and EPA blending data have been used to make the appropriate changes in the refinery model blending values for RVP and for VOCs.

As shown in the annualized Figure 31, a higher oxygen specification increases ethanol demand by as much as 16 percent. However, this demand increase is far short of the potential amount allowed by a higher oxygen specification—ethanol demand would be 5.2 BGY if the gasoline oxygen content were at the specification limit of 6 wt percent. Ethanol demand is suppressed by RVP and distillation specifications in summer. In winter, ethanol and butane are competing blendstocks, and butane blending economics can be more attractive. It is difficult to use both butane and ethanol because both components have costly volatility blending properties.

Follow-up consideration of any gasoline quality change, including a change in the oxygen specification, would rely on guidance of both automakers and refiners. Automakers have expressed concerns about the adverse effect of ethanol on hot driveability. They are also concerned about maintaining precise control of the air/fuel ratio in future vehicles. Increasing the ethanol concentration in gasoline blends will make this control more difficult due to the increased range of oxygen in the in-use vehicles' fuel tanks. In their World-Wide Fuel Charter, the automobile industry is suggesting to lower the oxygen content (forcing ethanol even lower than 10 vol percent) in "Category 3" gasoline, which is intended for markets with advanced requirements for emissions control (Prakash, 1998).

7.5 LOW SULFUR GASOLINE

EPA believes that reduction of sulfur in gasoline may be required to enable use of advanced vehicle pollution control technologies. Ethanol may have increased value because of its sulfur dilution effect

Fig. 31. Effect of gasoline oxygen specification on ethanol used in PADD II gasoline production and finishing in year 2010 - reference conditions

and high octane. Ethanol demand has been estimated for PADD II summer, with production of 100 percent LSG at 100 ppm sulfur. PADD II has been selected for this case study because desulfurization requirements are driven by the size and quality of the CG pool, and ethanol is a more attractive blendstock for summer CG relative to RFG. Within PADD II, the production share of CG is high.

Figure 32 shows that a requirement for LSG substantially increases the demand for ethanol when its refiner value is in the range of \$0.85 - \$1.10 per gallon. The ethanol demand increase is partly due to benefits of ethanol in sulfur reduction through dilution. In conventional hydrocarbon processing, there is a loss of octane in the reduction of sulfur (through saturation of olefins), and the ethanol demand increase is also related to octane recovery. Among the important refining strategies in sulfur reduction are dilution with ethanol, investment in hydroprocessing capacity, and purchase of low sulfur crude oils. These strategies compete with one another. As shown in Figures 33 and 34, as the value of ethanol increases, the demand for ethanol falls, investment in hydroprocessing capacity increases, and the sulfur content of crude oil decreases. With the fall in ethanol demand, ethanol's dilution effect on sulfur is decreased, but compensating sulfur reduction is achieved through process investments and through the use of cleaner crude oils.

It is important to recognize that the LSG program will be less costly if less than 100 percent of gasoline is LSG. Ethanol demand will be less with a smaller LSG program. On the other hand, ethanol demand could be higher with a lower sulfur specification for LSG.

7.6 VOLATILE ORGANIC COMPOUND SPECIFICATION WAIVER

Limitations on VOC emissions make summer RFG difficult to produce with high vapor pressure oxygenates like ethanol, and proponents of ethanol use in RFG have sought relief from the current VOC specification. In a sensitivity study, the premised VOC specification for ethanol-based RFG allows a 5 percent increase in VOC emissions. The VOC waiver premise is equivalent to a 0.5-0.7 psi RVP allowance for ethanol-based RFG. The waiver decreases the VOC advantage of MTBE-based RFG. Figure 35 shows the ethanol demand increase with the VOC waiver in PADD II. The demand increase is muted by the fact that only 11 percent of gasoline produced in PADD II gasoline is RFG. The effect of the waiver could be a significant increase in ethanol demand with an RFG production share of 30 percent—the national average.

7.7 TOXIC AIR POLLUTANT CORRECTION

The EPA Complex Model for emissions of pollutants does not account for TAP emissions due to evaporative and exhaust emissions of MTBE. If TAP due to MTBE were accounted for, ethanol could have an additional advantage in gasoline blending. EPA has provided estimates of exhaust and non-exhaust emissions of MTBE for a representative RFG, and these MTBE emissions have been converted to a benzene-equivalent toxicity based on cancer potency factors estimated by the Northeast States for Coordinated Air Use Management.

In an ORNL-RYM sensitivity study, the TAP specification for ethanol-containing RFG has been increased by the benzene-equivalent toxicity due to MTBE, which is not accounted for in the EPA Complex Model. The TAP allowance for ethanol-containing RFG has been increased by 12 percent to

Fig. 32. Low sulfur gasoline effect on ethanol used in PADD II gasoline production and finishing
in year 2010 summer

Fig. 33. Low sulfur gasoline effect on ethanol demand and refinery investment in PADD II gasoline production and finishing in year 2010 summer

Fig. 34. Low sulfur gasoline effect on ethanol demand and crude oil quality in PADD II gasoline production and finishing in year 2010 summer

Fig. 35. Effect of RFG VOC waiver on ethanol used in PADD II gasoline production and finishing in year 2010

remove the advantage in the TAP model for MTBE-containing RFG. No assumptions are made about possible bias against ETBE-containing RFG.

Figure 36 shows that the TAP correction has virtually no effect on ethanol demand in PADD II. Ethanol-containing RFG uses only part of the additional TAP allowance. If the TAP allowance had been increased by only 4 percent, the ethanol demand curve would have been exactly the same. The effect of the low RFG production share is not known for this case.

7.8 OCTANE INCREASE

The likelihood of an increase in octane specification is uncertain, but nonetheless plausible. For example, higher compression ratios may be needed to achieve higher efficiencies. At higher compression ratios, higher octane gasolines might be needed to inhibit preignition. With a blending octane $[(R+M)/2]$ that is nearly 25 numbers higher than the gasoline pool specification, ethanol is a very significant source of octane numbers. Figure 37 shows a correspondingly significant increase in ethanol demand when the octane specification for gasoline has been increased by 1 number.

7.9 ALTERNATIVE FORM OF ORNL-RYM

Overoptimization can occur as a result of ORNL-RYM's use of a modeling concept in which refinery streams with identical distillation cut points are kept separate through different refining processes. This modeling concept allows variations in key properties (e.g., sulfur content in gasoline) to be represented by linear combinations of streams with identical distillation cut points. Ratio constraints on refinery streams can be used to avoid unrealistic separation of streams with identical distillation cut points. With ratio constraints, the proportions of streams entering a process are constrained to equal the proportions of those streams produced at a source process.

It is important to recognize that refineries within a region can vary widely in technical capability, and that refineries are subject to temporal variations in complex operations. Refining activities span a range, and this range has uncertainty. Given variations, uncertainties, and over/underoptimization possibilities, DOE has concluded that two versions of ORNL-RYM can provide plausible estimates of the range of refining activities. The Ratio-constrained version is useful in identifying both order-of-magnitude and detailed changes in refinery operations and investments, but analytical costs are very high. The Ratio-free version can identify important order-of-magnitude changes in refinery operations and investments.

The Ratio-free version of ORNL-RYM has been used in the previously discussed ethanol demand case studies. A sensitivity case has examined the effect of the Ratio-constrained model on ethanol demand estimation for PADD III summer production. Because it is not possible to parametrically estimate the ethanol demand curve with the Ratio-constrained version, a comparison is based on one value point on the demand curve. This comparison suggests that Ratio-free modeling (the basis for all other study cases) is a conservative approach for ethanol demand estimation. With ratio constraints, the value of hydrocarbons increases significantly, which favors the blending of ethanol. As shown in Figure 38, the shallow slope of the (parametric) demand curve can amplify the demand differences. For the Ratio-constrained model case, ethanol demand is 29 percent higher than with the Ratio-free model. However,

Fig. 36. Effect of toxic air pollutant waiver on ethanol used in PADD II gasoline production and finishing in year 2010 summer

Fig. 37. Effect of increase in gasoline octane specification on ethanol used in PADD II gasoline production and finishing in year 2010 summer

Fig. 38. ORNL-RYM version effects on estimation of ethanol used in PADD III gasoline production and finishing
Year 2010 summer - reference conditions

for a given demand level, the value of ethanol for the Ratio-constrained model case is only 6 percent higher than the demand curve.

7.10 LATEST DATA FOR PREMISES

Key data for ethanol demand studies are based on *Annual Energy Outlook 1996* (DOE 1996a). Table 29 illustrates that there can be significant changes in the outlook for oil prices and refinery product supply. To evaluate the impact of outlook changes, a sensitivity case for ethanol demand in PADD III summer gasoline production has been examined with data of the more recently published *Annual Energy Outlook 1998* (DOE 1997a). Tables 30 and 31 show changes in product and raw material input data.

Table 29. Comparison of <i>Annual Energy Outlook</i> projections for year 2010		
	<i>Annual Energy Outlook 1996</i> (DOE 1996a)	<i>Annual Energy Outlook 1998</i> (DOE 1997a)
World oil price, \$ per barrel	23.70 (1994 dollars)	20.81 (1996 dollars)
Motor gasoline supplied, MMBD	8.64	9.75

Table 30. PADD III product slate for year 2010 reference conditions, different outlooks

Summer, <i>Annual Energy Outlook 1996</i> (DOE 1996a)			Summer, <i>Annual Energy Outlook 1998</i> (DOE 1997a)		
PRODUCT	\$/BARREL	MBD	PRODUCT	\$/BARREL	MBD
PROCESS GAS C2-FOE	15.67		PROCESS GAS C2-FOE	13.52	
STILL GAS TO PETROCHEM	15.67		STILL GAS TO PETROCHEM	13.52	
ETHANE FOE	15.67		ETHANE FOE	13.52	
ETHANE FOE	15.67		ETHANE FOE	13.52	
ETHYLENE FOE	15.67		ETHYLENE FOE	13.52	
PROPYLENE TO PETROCHEM	20.67		PROPYLENE TO PETROCHEM	17.84	
PROPANE FUEL(LPG)	16.81		PROPANE FUEL(LPG)	14.51	
PROPANE TO PETROCHEM	16.81		PROPANE TO PETROCHEM	14.51	
NORMAL BUTANE	20.12		NORMAL BUTANE	17.36	
SURPLUS NC4	20.12		SURPLUS NC4	17.36	
N BUTYLENE	21.00		N BUTYLENE	18.12	
ISO BUTANE	21.50		ISO BUTANE	18.55	
ISO BUTYLENE	21.00		ISO BUTYLENE	18.12	
CG WITH ETHERS	32.24		CG WITH ETHERS	27.67	
CG WITH ETHANOL	32.24		CG WITH ETHANOL	27.67	
*CG PRODUCTION SUMS TO 2982 MBD EQUIVALENT			*CG PRODUCTION SUMS TO 3240 MBD EQUIVALENT		
RFG WITH ETHERS	33.58		RFG WITH ETHERS	29.01	
RFG WITH ETHANOL	33.58		RFG WITH ETHANOL	29.01	
*RFG PRODUCTION SUMS TO 640 MBD EQUIVALENT			*RFG PRODUCTION SUMS TO 696 MBD EQUIVALENT		
AVIATION GAS	34.89	14	AVIATION GAS	30.32	15.7
MIL JET FUEL JP8	29.53	139.6	MIL JET FUEL JP8	24.96	166
COMMERCIAL JET A	29.48	728.7	COMMERCIAL JET A	24.91	877.1
2D ON-HIGHWAY DIESEL	29.13	950.3	2D ON-HIGHWAY DIESEL	24.56	967.2
HEATING OIL (NO2)	28.45	563.8	HEATING OIL (NO2)	23.88	536.2
RESIDUAL <.3S	21.98		RESIDUAL <.3S	18.45	
NET RESIDUAL 0.7-1.0 %	20.95	85.7	NET RESIDUAL 0.7-1.0 %	17.58	78.8
BUNKER	19.73		BUNKER	16.56	
*RESID PRODUCTION SUMS TO 358.4 MBD			*RESID PRODUCTION SUMS TO 329.6 MBD		
NAPHTHA TO P.CHEM	26.42		NAPHTHA TO P.CHEM	21.85	
AROMATICS TO P. CHEM	40.57		AROMATICS TO P. CHEM	36.00	
GAS OIL TO PETROCHEM	25.65		GAS OIL TO PETROCHEM	21.08	
*PETROCHEM PRODUCTION SUMS TO 58.5 MBD			*PETROCHEM PRODUCTION SUMS TO 58.5 MBD		
LUBES & WAXES	38.62	112.1	LUBES & WAXES	32.42	133.7
COKE ST/CD LOW SULF	57.66		COKE ST/CD LOW SULF	48.40	
COKE ST/CD HIGH SULF	32.97		COKE ST/CD HIGH SULF	27.67	
COKE ST/CD XTRA HI SULF	7.21		COKE ST/CD XTRA HI SULF	6.05	
ROAD OIL & ASPHALT	21.19	136.0	ROAD OIL & ASPHALT	17.79	142.0
SULFUR	69.18		SULFUR	58.06	

Table 31. PADD III raw material options for year 2010 reference conditions, different outlooks

Summer, Annual Energy Outlook 1996 (DOE 1996a)			Summer, Annual Energy Outlook 1998 (DOE 1997a)		
CRUDE/RAW MATERIAL	\$/BARREL	MBD	CRUDE/RAW MATERIAL	\$/BARREL	MBD
ALGERIAN SAHARAN	28.60	24	ALGERIAN SAHARAN	24.01	28
KUWAIT	24.93	152	KUWAIT	20.93	180
SAUDI ARABIAN BERRI	25.96	173	SAUDI ARABIAN BERRI	21.78	206
SAUDI ARABIAN LIGHT	25.73		SAUDI ARABIAN LIGHT	21.60	
SAUDI ARABIAN MEDIUM	24.45	414	SAUDI ARABIAN MEDIUM	20.53	490
SAUDI ARABIAN HEAVY	23.78		SAUDI ARABIAN HEAVY	19.96	
UAE - DUBAI	25.73	9	UAE - DUBAI	21.60	11
GABON	25.15	202	GABON	21.11	240
INDONESIAN MINAS	25.51	3	INDONESIAN MINAS	21.41	4
NIGERIAN MEDIUM	24.69	140	NIGERIAN MEDIUM	20.72	166
NIGERIAN LIGHT	28.20	72	NIGERIAN LIGHT	23.68	85
NIGERIAN FORCADOS	26.22	130	NIGERIAN FORCADOS	22.01	154
VENEZ MED (TJ MED)	24.04	643	VENEZ MED (TJ MED)	20.18	763
VEN BACH 17 / 2.4	20.90	351	VEN BACH 17 / 2.4	17.54	417
VEN XHVV BOSCAN 11.2/4	19.89	<10	VEN XHVV BOSCAN 11.2/4	16.70	<12
ANGOLAN	25.36	227	ANGOLAN	21.29	269
COLOMBIAN	25.67	186	COLOMBIAN	21.55	220
CONGO	24.69	37	CONGO	20.72	44
ECUADOR	25.64	77	ECUADOR	21.52	92
EGYPT GHARIB/BAKR	24.50	<28	EGYPT GHARIB/BAKR	20.57	<33
GUATEMALA	25.81	9	GUATEMALA	21.67	11
MALAYSIA LABUAN	26.47	3	MALAYSIA LABUAN	22.21	3
MEXICAN ISTHMUS	25.71	269	MEXICAN ISTHMUS	21.58	320
MEXICAN MAYA	22.34	902	MEXICAN MAYA	18.75	<1070
NORWAY	26.03	187	NORWAY	21.85	221
OMAN	25.70	11	OMAN	21.57	13
RUSSIA	25.70	49	RUSSIA	21.57	58
TRINIDAD SWEET LS	26.99	38	TRINIDAD SWEET LS	22.65	45
TRINIDAD SOUR HS	25.22	38	TRINIDAD SOUR HS	21.17	45
UK	26.03	<500	UK	21.85	<500
ZAIRE	25.36	18	ZAIRE	21.29	22
ALABAMA HVY	26.12	23	ALABAMA HVY	21.93	25
ALABAMA LIGHT	27.21	14	ALABAMA LIGHT	22.85	15
ARKANSAS	24.02	26	ARKANSAS	20.17	27
LOUISIANA COND	27.39	86	LOUISIANA COND	22.99	91
LOUISIANA NORTH	27.26	50	LOUISIANA NORTH	22.89	52
LOUISIANA S.MIX/OFFSHORE	26.55	430	LOUISIANA S.MIX/OFFSHORE	22.29	452
MISSISSIPPI HEY	26.97	15	MISSISSIPPI HEY	22.63	16
MISSISSIPPI BAX	25.77	31	MISSISSIPPI BAX	21.63	33
NEW MEXICO INT	28.52	19	NEW MEXICO INT	23.94	20
NEW MEXICO SOUR	25.85	38	NEW MEXICO SOUR	21.70	40
TEXAS CONDENSATE	29.30	65	TEXAS CONDENSATE	24.60	69
TEXAS GULF REF	26.65	380	TEXAS GULF REF	22.37	399
TEXAS EAST	27.03	61	TEXAS EAST	22.69	64
TEXAS HAWKINS	23.06	122	TEXAS HAWKINS	19.36	128
TEXAS WEST INTERMED	27.19	344	TEXAS WEST INTERMED	22.83	361
TEXAS WEST SOUR	25.85	83	TEXAS WEST SOUR	21.80	87
OKLA CEMENT	24.62	22	OKLA CEMENT	20.66	23
CALIFORNIA ELK HILLS	25.43	41	CALIFORNIA ELK HILLS	21.36	43
ALASKAN NORTH SLOPE	25.05	21	ALASKAN NORTH SLOPE	21.03	22
NATURAL GAS (FOE)	16.70		NATURAL GAS (FOE)	16.93	
NATURAL GASOLINE	26.13	<109	NATURAL GASOLINE	21.56	<118
ISOBUTANE	22.36	<97	ISOBUTANE	19.41	<105
NORMAL BUTANE	20.98		NORMAL BUTANE	18.22	
ETHANOL	27.74		ETHANOL	27.74	
METHANOL	25.60		METHANOL	26.09	
MTBE	47.47		MTBE	44.75	
ETBE	47.90		ETBE	45.18	
NAPHTHA/REF FEED	26.67	<68.2	NAPHTHA/REF FEED	22.10	<40.6
GAS OIL	26.29	<116.7	GAS OIL	21.72	<69.6

Due to increased gasoline volume with the 1998 outlook, ORNL-RYM estimates a gasoline value that is inconsistently higher than the gasoline price projection. Because the gasoline value is high, the demand for ethanol is high.

With a significant relaxation of the raw material slate, the value of gasoline becomes consistent with the gasoline price projection of the 1998 outlook. For these conditions, ethanol demand is essentially the same as the estimate with input data based on the 1996 outlook. A point-by-point estimation of ethanol demand (with point-specific relaxation of raw materials) is expected to have the same result: the ethanol demand curve based on *Annual Energy Outlook 1998* (DOE 1997a) would be similar to the ethanol demand curve based on the *Annual Energy Outlook 1996* (DOE 1996a). With a lower premised oil value, the expected decline in ethanol demand has been off-set by the increased gasoline production volume.

8. REFINING IMPACTS FOR ETHANOL USE IN GASOLINE PRODUCTION AND FINISHING

8.1 PADD I

Summer and winter summaries for gasoline properties, gasoline blendstocks, key process balances, investment, and crude quality are shown for reference conditions for PADD I refineries in Tables 32 through 36. Table 32 shows that the maximum allowable amount of ethanol is used for CG in both summer and winter at the low ethanol value of \$0.65 per gallon. ETBE is the primary oxygenate for summer RFG (Table 33). Because there is no VOC specification for winter gasoline, there is a large increase ethanol blended to winter RFG. Ethanol demand is about the same in both seasons.

8.2 PADD II REFINING IMPACTS ACROSS CASE CONDITIONS

Tables 37 through 46 show summer and winter summaries for gasoline properties, gasoline blendstocks, key process balances, investment, and crude quality for PADD II refineries for reference and for higher demand conditions.

For higher ethanol demand conditions versus reference conditions in summer, the increase in ethanol demand (4 percent) is comparable to the increase in gasoline production (3 percent). The oxygen content of RFG blended with ethanol increases from 2.1 to 2.7 percent. A 6 percent increase in production of distillates (highway diesel fuel and home heating oil) is about twice the increase for gasoline (excluding ethanol). Process utilization and investment changes focus on resid processing and distillate desulfurization.

Compared with summer, winter ethanol for higher ethanol demand conditions enjoys a \$0.02 per gallon advantage in the refiner value difference relative to gasoline. So the increase in ethanol demand (34 percent) is large compared to the increase in gasoline production (3 percent). Most of the increase in ethanol demand occurs in the production of CG with ethanol, with an end to production of CG with low ether content. There is a 6 percent increase in production of distillates, while gasoline (excluding ethanol) production increases only 1 percent. There is decreased utilization of reformers, which produce gasoline blendstocks and hydrogen. With increased requirements for distillate desulfurization, investment is required in hydrogen production capacity.

8.3. PADD III

8.3.1 Refining Impacts within a Case

Within-case comparisons of refinery impacts of ethanol demand changes are made for PADD III for year 2010 summer reference conditions at two ethanol demand points:

1. ethanol at refiner value of \$0.83 per gallon, with demand of 1.8 BGY, and
2. ethanol at refiner value of \$0.48 per gallon, with demand of 5.1 BGY.

Table 32. Gasoline properties in PADD I for year 2010 reference conditions

	Summer				Winter			
	CG		RFG		CG		RFG	
	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal
Volume, MBD	0	324	475	29	0	326	52	454
Octane, (R+M)/2		90.0	89.7	89.5		89.4	89.4	89.5
RVP, psi		9.2	6.9	6.7		13.8	13.8	13.8
Aromatics, vol %		33.6	24.0	31.4		31.0	24.6	27.1
Benzene, vol %		2.08	0.95	0.67		1.49	0.95	0.85
Olefins, vol %		16.1	13.4	14.4		13.5	17.5	16.9
Sulfur, ppm		382	121	86		390	151	151
E200, %		59.7	49.4	44.5		64.6	63.1	62.2
E300, %		86.0	84.6	87.5		88.2	84.4	86.4
Oxygen, wt %		3.50	2.70	2.11		3.50	2.69	2.70
Specific gravity		.7469	.7430	.7581		.7433	.7310	.7296
TAP, mg/mi		91.8	64.3 ^a	64.3 ^a		117.7 ^a	98.1 ^a	98.3 ^a
NOx, mg/mi		1437 ^a	1249 ^a	1249 ^a		1600 ^a	1518 ^a	1517 ^a
VOC, mg/mi		1431	1019 ^a	1019 ^a				
^a Binding emissions constraint.								

Table 33. Gasoline blendstocks in PADD I for year 2010 reference conditions

Blendstock	Summer				Winter			
	CG		RFG		CG		RFG	
	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal
Butane		1.7	1.5	1.5		11.1	12.3	9.6
Reformat		20.6	25.1	30.6		26.9	16.7	16.9
Straight run naphtha		3.9	10.7			13.7	17.4	2.8
C5+ isomerate		2.3	1.9					3.5
FCC naphtha		47.4	30.7	26.2		30.9	37.1	43.5
Coker naphtha								
Hydrocrackate		6.5	2.3	28.8				7.4
Alkylate		8.2	8.5	5.2		7.0		7.3
Polymer gasolines			1.8			1.0		1.7
Dimate			0.5	1.9				0.3
Ethanol		9.4		5.8		9.4		7.1
ETBE			15.4				13.4	
MTBE			1.5				3.0	
Natural gasoline								
Pyrolysis gasoline								
Other			0.1					

Table 34. Hydrogen balance for PADD I for year 2010 reference conditions

Entry at top of cell is fuel oil equivalent barrels of hydrogen per day
(minus sign indicates consumption)

Entry at bottom of cell is process unit utilization
(calendar rate divided by stream day capacity^a x 100 percent)

Process	Summer	Winter
Naphtha hydrotreating	-997 (73)	-794 (66)
Distillate desulfurization	-5229 (85)	-5241 (85)
FCC feed hydrofining	-1045 (64)	-1263 (80)
Gas oil hydrocracking	-7615 (87)	-7242 (81)
Reforming	+10729 (69)	+10613 (64)
C4 isomerization	-15 (89)	-14 (85)
C5/C6 isomerization	-34 (89)	-33 (85)
Ether production	-71 (87)	-66 (81)
Hydrogen production	+5652 (89)	+5398 (85)
Hydrogen to fuel and losses	-1373	-1358

^aFor comparability of summer and winter utilization, stream day capacity equals current in-place capacity plus announced construction.

Table 35. Process capacity additions in PADD I for year 2010 reference conditions ^a		
Process ^b	Summer ^c	Winter ^d
Crude distillation		68
Vacuum distillation	8	41
Middle distillate deep hydrotreating	15	
FCC naphtha fractionation	34	
Distillate fractionation	1	
\$Million	184	352
^a Thousand barrels per day. ^b Investment decisions are based on a 15% DCF return on investment. ^c Summer capacity is current in-place plus announced construction plus investment from column 2. ^d Winter capacity is summer capacity plus investment.		

Table 36. Quality of crude oil processed in PADD I for year 2010 reference conditions		
Property	Summer	Winter
Sulfur content, wt %	0.80	0.77
Gravity, °API	31.2	31.5

Table 37. Gasoline properties in PADD II for year 2010 reference conditions

	Summer				Winter			
	CG		RFG		CG		RFG	
	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.51/gal	With ethers	With ethanol @ \$.51/gal
Volume, MBD	0	1755	122	110	336	1326	29	192
Octane, (R+M)/2		88.3	88.2	88.2	88.2	88.2	88.2	88.2
RVP, psi		9.4	7.1	6.9	14.2	14.2	14.2	14.2
Aromatics, vol %		25.7	21.4	30.1	23.1	25.7	19.1	20.6
Benzene, vol %		1.37	0.95	0.79	1.65	1.18	0.94	0.95
Olefins, vol %		13.0	13.4	14.4	15.3	12.9	13.0	11.3
Sulfur, ppm		323	113	81	194	269	300	292
E200, %		59.7	59.7	48.0	64.6	64.6	65.1	64.6
E300, %		88.2	84.6	88.8	82.2	89.5	85.1	87.7
Oxygen, wt %		3.50	2.10	2.10	0.27	3.50	2.16	2.17
Specific gravity		.7448	.7267	.7587	.7104	.7381	.7096	.7167
TAP, mg/mi		74.3	62.3	64.3 ^a	109.0 ^a	103.2	98.3 ^a	96.7
NOx, mg/mi		1367	1249 ^a	1248 ^a	1515	1530	1518 ^a	1505
VOC, mg/mi		1461	1020 ^a	1020 ^a				
^a Binding emissions constraint.								

Table 38. Gasoline blendstocks in PADD II for year 2010 reference conditions

Blendstock	Summer				Winter			
	CG		RFG		CG		RFG	
	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.51/gal	With ethers	With ethanol @ \$.51/gal
Butane		2.5	1.5	1.5	10.1	11.8	13.6	9.4
Reformate		23.8	19.5	43.8	13.0	27.0	4.1	14.1
Straight run naphtha		11.4				11.3	4.8	
C5+ isomate		5.6	29.9		17.6	1.8	20.2	19.9
FCC naphtha		31.9	33.6	17.8	45.5	25.5	44.2	38.4
Coker naphtha		0.9				1.3		
Hydrocrackate		1.5		25.2	7.1			12.5
Alkylate		12.1		1.0	5.1	8.1		
Polymer gasolines		0.4	2.5	1.6		0.8		
Dimate				3.4				
Ethanol		9.4		5.8		9.3		5.6
ETBE			13.1		1.7		13.1	
MTBE								
Natural gasoline		0.6				3.0		
Pyrolysis gasoline								
Other								

Table 39. Hydrogen balance for PADD II for year 2010 reference conditions

Entry at top of cell is fuel oil equivalent barrels of hydrogen per day
(minus sign indicates consumption)

Entry at bottom of cell is process unit utilization
(calendar rate divided by stream day capacity ^a x 100 percent)

Process	Summer	Winter
Naphtha hydrotreating	-2083 (67)	-1907 (59)
Distillate desulfurization	-13689 (93)	-14509 (97)
FCC feed hydrofining	-7679 (80)	-6392 (67)
Gas oil hydrocracking	-11806 (83)	-9900 (69)
Reforming	+29758 (68)	+26705 (59)
C4 isomerization	-37 (84)	-35 (80)
C5/C6 isomerization	-278 (84)	-261 (79)
Ether production	-79 (83)	-73 (77)
Hydrogen production	+16310 (83)	+15720 (80)
Hydrogen to fuel and losses	-10415	-9347

^a For comparability of summer and winter utilization, stream day capacity equals current in-place capacity plus announced construction.

Table 40. Process capacity additions in PADD II for year 2010 reference conditions ^a		
Process ^b	Summer ^c	Winter ^d
Visbreaking	28	
Middle distillate deep hydrotreating	175	19
\$Million	1266	109
^a Thousand barrels per day. ^b Investment decisions are based on a 15% DCF return on investment. ^c Summer capacity is current in-place plus announced construction plus investment from column 2. ^d Winter capacity is summer capacity plus investment.		

Table 41. Quality of crude oil processed in PADD II for year 2010 reference conditions		
Property	Summer	Winter
Sulfur content, wt %	1.14	1.07
Gravity, °API	33.6	33.6

Table 42. Gasoline properties in PADD II for year 2010 higher ethanol demand conditions

	Summer				Winter			
	CG		RFG		CG		RFG	
	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.51/gal	With ethers	With ethanol @ \$.51/gal
Volume, MBD	0	1809	142	97	0	1722	72	155
Octane, (R+M)/2		88.4	88.2	88.2		88.3	88.8	88.5
RVP, psi		9.4	7.1	6.9		14.2	14.2	14.2
Aromatics, vol %		26.4	21.0	29.1		22.5	16.0	21.1
Benzene, vol %		1.73	0.95	0.91		1.06	0.59	0.74
Olefins, vol %		12.3	13.6	11.3		13.7	13.5	9.9
Sulfur, ppm		312	113	82		234	232	323
E200, %		59.7	59.7	48.9		64.6	64.6	64.6
E300, %		88.4	84.2	90.1		89.5	91.2	90.1
Oxygen, wt %		3.50	2.10	2.70		3.50	2.16	2.16
Specific gravity		.7459	.7264	.7577		.7309	.7069	.7173
TAP, mg/mi		79.1	62.2	64.1 ^a		98.3	89.9	95.1
NOx, mg/mi		1358	1249 ^a	1220		1507	1468	1508
VOC, mg/mi		1462	1021 ^a	1020 ^a				

^aBinding emissions constraint.

Table 43. Gasoline blendstocks in PADD II for year 2010 higher ethanol demand conditions

Blendstock	Summer				Winter			
	CG		RFG		CG		RFG	
	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.51/gal	With ethers	With ethanol @ \$.51/gal
Butane		2.4	1.5	1.5		11.5	11.0	8.7
Reformate		26.0	17.4	36.1		18.2	30.7	20.0
Straight run naphtha		9.8		1.4		11.2	2.4	
C5+ isomerate		4.7	32.1	4.6		5.2	14.9	16.6
FCC naphtha		29.9	34.1	19.5		30.4	21.1	31.2
Coker naphtha		0.9				1.2		
Hydrocrackate		1.5		28.4		1.4		15.2
Alkylate		11.9		1.1		11.4		2.1
Polymer gasolines		0.5	1.9			0.3	6.9	0.4
Dimate								
Ethanol		9.5		7.4		9.3		5.6
ETBE			13.1				13.1	
MTBE								
Natural gasoline		3.1						
Pyrolysis gasoline								
Other								

Table 44. Hydrogen balance for PADD II for year 2010 higher ethanol demand conditions

Entry at top of cell is fuel oil equivalent barrels of hydrogen per day
(minus sign indicates consumption)

Entry at bottom of cell is process unit utilization
(calendar rate divided by stream day capacity ^a x 100 percent)

Process	Summer	Winter
Naphtha hydrotreating	-2103 (67)	-1838 (55)
Distillate desulfurization	-15234 (100)	-15652 (105)
Resid desulfurization		-149 (46)
FCC feed hydrofining	-6481 (68)	-7916 (83)
Gas oil hydrocracking	-11452 (83)	-9669 (66)
Reforming	+29777 (68)	+25413 (51)
C4 isomerization	-37 (84)	-35 (80)
C5/C6 isomerization	-278 (84)	-261 (79)
Ether production	-79 (83)	-73 (77)
Hydrogen production	+16310 (83)	+19076 (97)
Hydrogen to fuel and losses	-10422	-8895

^a For comparability of summer and winter utilization, stream day capacity equals current in-place capacity plus announced construction.

Table 45. Process capacity additions in PADD II for year 2010 higher ethanol demand conditions ^a		
Process ^b	Summer ^c	Winter ^d
Vacuum distillation	62	19
Visbreaking	36	
Middle distillate deep hydrotreating	201	11
Hydrogen production, fuel oil equivalent barrels per day		3
\$Million	1650	445
^a Thousand barrels per day. ^b Investment decisions are based on a 15% DCF return on investment. ^c Summer capacity is current in-place plus announced construction plus investment from column 2. ^d Winter capacity is summer capacity plus investment.		

Table 46. Quality of crude oil processed in PADD II for year 2010 higher ethanol demand conditions		
Property	Summer	Winter
Sulfur content, wt %	1.15	1.14
Gravity, °API	33.5	33.0

Gasoline properties, gasoline blendstocks, key process balances, investment, and crude quality summaries for these demand points are shown in Tables 47 through 51. With higher ethanol demand, gasoline production (excluding ethanol) falls 4 percent. Most of the increase in ethanol demand occurs in the production of CG with ethanol, with an end to production of oxygenate-free CG.

With the addition of ethanol to gasoline, high quality gasoline blendstocks are reduced: reformate (down 8 percent), isomate (down 87 percent), FCC naphtha (down 1 percent); hydrocrackate (down 6 percent), and alkylate (down 21 percent). Lower quality naphthas blended to gasoline increase by nearly 140 percent.

With a decrease in gasoline production, utilization falls at naphtha hydrotreating, gas oil hydrocracking, reforming and alkylation units. The hydrogen production loss at reformers is accommodated by a drop

Table 47. Gasoline properties in PADD III for year 2010 summer reference conditions

	Ethanol @ \$0.83/gallon (1.8 BGY ethanol)				Ethanol @\$0.48/gallon (5.1 BGY ethanol)			
	CG		RFG		CG		RFG	
	With ethers	With ethanol	With ethers	With ethanol	With ethers	With ethanol	With ethers	With ethanol
Volume, MBD	1785	1238	622	32	0	3084	554	101
Octane, (R+M)/2	89.0	89.0	89.0	89.0		89.0	89.0	89.0
RVP, psi	8.5	9.5	7.2	7.1		9.5	7.1	6.9
Aromatics, vol %	30.1	29.8	21.3	29.4		27.5	21.7	29.6
Benzene, vol %	1.82	2.07	0.95	0.95		1.40	0.95	0.94
Olefins, vol %	14.0	10.4	14.6	13.9		12.6	13.0	9.2
Sulfur, ppm	300	342	98	70		309	122	87
E200, %	45.0	59.7	59.7	59.7		59.7	59.2	54.8
E300, %	82.0	88.4	86.6	91.5		87.7	88.2	91.9
Oxygen, wt %	0.00	3.49	2.10	2.08		3.50	2.32	2.10
Specific gravity	.7355	.7500	.7326	.7581		.7455	.7384	.7587
TAP, mg/mi	87.8 ^a	87.8 ^a	58.7	64.1 ^a		76.0	62.5	64.2 ^a
NOx, mg/mi	1365 ^a	1364 ^a	1249 ^a	1248 ^a		1364 ^a	1249 ^a	1219
VOC, mg/mi	1360	1541	1031 ^a	1031 ^a		1526	1031 ^a	1030 ^a

^aBinding emissions constraint.

Table 48. Gasoline blendstocks in PADD III for year 2010 summer reference conditions

Blendstock	Ethanol @ \$0.83/gallon (1.8 BGY ethanol)				Ethanol @\$0.48/gallon (5.1 BGY ethanol)			
	CG		RFG		CG		RFG	
	With ethers	With ethanol	With ethers	With ethanol	With ethers	With ethanol	With ethers	With ethanol
Butane	1.5	2.7	1.5	1.5		2.4	1.6	1.5
Reformate	19.5	29.5	26.4	53.6		20.5	24.9	52.4
Straight run naphtha	5.0	4.7				9.0	12.9	
C5+ isomerate	4.8		12.2			0.3	2.2	
FCC naphtha	44.7	29.7	27.7	5.6		37.2	31.5	6.6
Coker naphtha	2.8					1.8		
Hydrocrackate	6.8	6.1	6.8	17.8		4.5	12.4	21.8
Alkylate	14.9	9.0	11.8	4.8		11.4		6.2
Polymer gasolines			1.0			0.8		
Dimate			1.1	11.0				5.7
Ethanol		9.5		5.7		9.5		5.8
ETBE							14.7	
MTBE			11.4					
Natural gasoline	8.8					2.7		
Pyrolysis gasoline								
Other								

Table 49. Hydrogen balance for PADD III for year 2010 summer reference conditions

Entry at top of cell is fuel oil equivalent barrels of hydrogen per day
(minus sign indicates consumption)

Entry at bottom of cell is process unit utilization
(calendar rate divided by stream day capacity^a x 100 percent)

Process	Ethanol @\$0.83/gallon (1.8 BGY ethanol)	Ethanol@\$0.48/gallon (5.1 BGY ethanol)
Naphtha hydrotreating	-3745 (66)	-3015 (54)
Distillate desulfurization	-22738 (77)	-22393 (76)
Resid desulfurization	-8022 (92)	-8022 (92)
FCC feed hydrofining	-14166 (75)	-14760 (78)
Gas oil hydrocracking	-56191 (87)	-52248 (82)
Reforming	+68889 (61)	+61758 (55)
C4 isomerization	-83 (89)	-83 (89)
C5/C6 isomerization	-333 (89)	-45 (12)
Ether production	-555 (68)	-633 (78)
Hydrogen production	+61054 (89)	+61054 (89)
Hydrogen to fuel and losses	-24111	-21615

Table 50. Process capacity additions in PADD III for year 2010 summer reference conditions ^a		
Process ^b	Ethanol @\$0.83/gallon (1.8 BGY ethanol)	Ethanol@\$0.48/gallon (5.1 BGY ethanol)
Solvent deasphalting	36	41
Middle distillate deep hydrotreating	49	40
\$Million	482	465
^a Thousand barrels per day. ^b Investment decisions are based on a 15% DCF return on investment.		

Table 51. Quality of crude oil processed in PADD III for year 2010 summer reference conditions		
Property	Ethanol @\$0.83/gallon (1.8 BGY ethanol)	Ethanol@\$0.48/gallon (5.1 BGY ethanol)
Sulfur content, wt %	1.35	1.36
Gravity, °API	31.2	31.1

in hydrogen demand at the hydrocrackers. Some process capacity becomes available for distillate processing, and investment in distillate hydrotreating decreases.

8.3.2 Refining Impacts across Case Conditions

Tables 52 through 61 show summer and winter summaries for gasoline properties, gasoline blendstocks, key process balances, investment, and crude quality for PADD III refineries for reference and for higher demand conditions.

For higher ethanol demand conditions versus reference conditions in summer, the increase in ethanol demand (8 percent) is higher than the increase in gasoline production (3 percent). Compared with PADD II, which has a lower increase in summer ethanol demand, PADD III summer ethanol for higher ethanol demand conditions enjoys a small advantage (\$0.003 per gallon) in the refiner value difference relative to gasoline. The increase in ethanol demand occurs in both CG and RFG. There is a 6 percent increase in production of distillates, and gasoline production (excluding ethanol) increases only 2 percent. Octane production falls at the reformers, with a decrease in hydrogen production. With increased requirements for distillate desulfurization, there is investment in hydrogen production capacity.

Table 52. Gasoline properties in PADD III for year 2010 reference conditions

	Summer				Winter			
	CG		RFG		CG		RFG	
	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.51/gal	With ethers	With ethanol @ \$.51/gal
Volume, MBD	85	2997	610	45	1460	1480	127	511
Octane, (R+M)/2	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0
RVP, psi	8.5	9.5	7.1	6.6	13.5	13.5	13.5	13.5
Aromatics, vol %	34.5	27.3	24.6	25.1	22.8	32.1	22.8	22.8
Benzene, vol %	1.65	1.37	0.95	0.95	1.89	1.45	0.72	0.87
Olefins, vol %	9.1	12.7	11.8	9.14	12.9	9.1	9.1	9.1
Sulfur, ppm	343	307	119	163	176	191	334	344
E200, %	59.7	59.7	59.7	43.5	64.6	65.1	64.6	64.6
E300, %	84.2	87.5	87.9	91.9	83.1	88.2	88.8	93.0
Oxygen, wt %	0.0	3.52	2.09	2.10	0.58	3.50	2.26	3.51
Specific gravity	.7404	.7453	.7426	.7587	.7139	.7502	.7267	.7310
TAP, mg/mi	87.2 ^a	75.4	63.3	64.4 ^a	110.3 ^a	109.7	98.4 ^a	98.5 ^a
NOx, mg/mi	1366 ^a	1364 ^a	1249 ^a	1235	1475 ^a	1476 ^a	1517 ^a	1516 ^a
VOC, mg/mi	1346	1526	1031 ^a	1030 ^a				
^a Binding emissions constraint.								

Table 53. Gasoline blendstocks in PADD III for year 2010 reference conditions

Blendstock	Summer				Winter			
	CG		RFG		CG		RFG	
	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.51/gal	With ethers	With ethanol @ \$.51/gal
Butane	1.5	2.4	1.5	1.5	9.4	10.2	13.7	11.5
Reformate	32.6	19.8	34.7	25.5	10.7	39.3	40.6	18.8
Straight run naphtha	3.6	10.3	11.2		4.9	10.1		
C5+ isomerate	9.3	0.3	0.7		8.3			7.8
FCC naphtha	22.5	38.3	25.6	16.2	46.7	20.0	28.1	30.3
Coker naphtha								
Hydrocrackate	29.8	3.5	13.1	46.5	7.8		3.5	22.2
Alkylate	0.7	11.5		2.6	8.6	2.2		
Polymer gasolines		0.8		2.0		1.6		
Dimate								
Ethanol		9.5		5.8		9.5		9.3
ETBE			13.3		3.6		14.1	
MTBE								
Natural gasoline		3.6				7.0		
Pyrolysis gasoline								
Other								

Table 54. Hydrogen balance for PADD III for year 2010 reference conditions

Entry at top of cell is fuel oil equivalent barrels of hydrogen per day
(minus sign indicates consumption)

Entry at bottom of cell is process unit utilization
(calendar rate divided by stream day capacity ^a x 100 percent)

Process	Summer	Winter
Naphtha hydrotreating	-3065 (56)	-5617 (69)
Distillate desulfurization	-22336 (76)	-25504 (81)
Resid desulfurization	-8022 (92)	-7975 (92)
FCC feed hydrofining	-14700 (77)	-12101 (65)
Gas oil hydrocracking	-53190 (85)	-50400 (87)
Reforming	+63105 (57)	+63850 (59)
C4 isomerization	-83 (89)	-83 (89)
C5/C6 isomerization	-45 (12)	-333 (89)
Ether production	-633 (78)	-544 (67)
Hydrogen production	+61054 (89)	+61054 (89)
Hydrogen to fuel and losses	-22087	-22348

^a For comparability of summer and winter utilization, stream day capacity equals current in-place capacity plus announced construction.

Table 55. Process capacity additions in PADD III for year 2010 reference conditions ^a		
Process ^b	Summer ^c	Winter ^d
Solvent deasphalting	40	
Middle distillate deep hydrotreating	39	57
\$Million	453	282
^a Thousand barrels per day. ^b Investment decisions are based on a 15% DCF return on investment. ^c Summer capacity is current in-place plus announced construction plus investment from column 2. ^d Winter capacity is summer capacity plus investment.		

Table 56. Quality of crude oil processed in PADD III for year 2010 reference conditions		
Property	Summer	Winter
Sulfur content, wt %	1.36	1.35
Gravity, °API	31.3	31.3

Table 57. Gasoline properties in PADD III for year 2010 higher ethanol demand conditions

	Summer				Winter			
	CG		RFG		CG		RFG	
	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.51/gal	With ethers	With ethanol @ \$.51/gal
Volume, MBD	0	3176	513	163	362	2606	380	253
Octane, (R+M)/2		89.0	89.0	89.0	89.0	89.0	89.0	89.0
RVP, psi		9.54	7.2	7.0	13.5	13.5	13.5	13.5
Aromatics, vol %		26.1	18.7	26.1	26.0	26.0	18.6	18.6
Benzene, vol %		1.48	0.95	0.95	1.16	1.07	0.82	0.91
Olefins, vol %		13.3	14.0	10.0	8.6	12.1	8.6	8.6
Sulfur, ppm		305	133	94	213	181	422	429
E200, %		59.7	59.7	53.8	64.6	64.6	64.6	64.6
E300, %		87.3	90.4	91.7	84.2	88.6	92.6	94.1
Oxygen, wt %		3.50	2.50	2.65	0.56	3.49	2.26	2.69
Specific gravity		.7447	.7353	.7554	.7156	.7386	.7082	.7199
TAP, mg/mi		76.3	61.5	62.6	103.3	99.4	98.6 ^a	97.7
NOx, mg/mi		1365 ^a	1249 ^a	1218	1476 ^a	1476 ^a	1517 ^a	1517 ^a
VOC, mg/mi		1522	1032 ^a	1030 ^a				
^a Binding emissions constraint.								

Table 58. Gasoline blendstocks in PADD III for year 2010 higher ethanol demand conditions

Blendstock	Summer				Winter			
	CG		RFG		CG		RFG	
	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.51/gal	With ethers	With ethanol @ \$.51/gal
Butane		2.8	1.5	1.5	10.7	10.6	8.0	9.2
Reformate		18.9	20.0	46.9	18.3	25.0	6.1	8.2
Straight run naphtha		9.0	14.4			9.7	11.2	7.0
C5+ isomerate		0.3	2.4		14.8	1.3	19.2	
FCC naphtha		37.6	30.4	7.4	31.8	32.1	29.1	24.0
Coker naphtha		1.6	0.6			0.8		4.1
Hydrocrackate		4.1	13.8	22.0	13.1	2.2	12.6	29.2
Alkylate		13.6	1.1	8.6	7.8	8.0		
Polymer gasolines		0.1				0.9		
Dimate				6.3				
Ethanol		9.4		7.2		9.3		7.0
ETBE			15.7		3.4		13.7	
MTBE								
Natural gasoline								
Pyrolysis gasoline								
Other								

Table 59. Hydrogen balance for PADD III for year 2010 higher ethanol demand conditions

Entry at top of cell is fuel oil equivalent barrels of hydrogen per day
(minus sign indicates consumption)

Entry at bottom of cell is process unit utilization
(calendar rate divided by stream day capacity ^a x 100 percent)

Process	Summer	Winter
Naphtha hydrotreating	-2885 (55)	-4006 (60)
Distillate desulfurization	-24695 (82)	-30898 (88)
Resid desulfurization	-8016 (92)	-7970 (92)
FCC feed hydrofining	-14470 (77)	-11128 (87)
Gas oil hydrocracking	-57452 (87)	-48412 (83)
Reforming	+58564 (60)	+59088 (52)
C4 isomerization	-83 (89)	-83 (89)
C5/C6 isomerization	-47 (13)	-333 (89)
Ether production	-629 (77)	-503 (62)
Hydrogen production	+70211 (102)	+64926 (95) ^b
Hydrogen to fuel and losses	-20497	-20680

^aFor comparability of summer and winter utilization, stream day capacity equals current in-place capacity plus announced construction.

^bPemise error: winter hydrogen capacity does not include summer investment in this modeling case.

Table 60. Process capacity additions in PADD III for year 2010 higher ethanol demand conditions ^a		
Process ^b	Summer ^c	Winter ^d
Solvent deasphalting	137	61
Lube and wax units	6	3
Middle distillate deep hydrotreating	82	160
Hydrogen production, fuel oil equivalent barrels per day	9	4
\$Million	2425	1771
^a Thousand barrels per day. ^b Investment decisions are based on a 15% DCF return on investment. ^c Summer capacity is current in-place plus announced construction plus investment from column 2. ^d Winter capacity is summer capacity plus investment . However, a premise error was made for winter hydrogen capacity, which does not include summer investment for hydrogen capacity. Total refinery cost in the winter should be slightly higher because of this error, but the effect on ethanol demand should be negligible.		

Table 61. Quality of crude oil processed in PADD III for year 2010 higher ethanol demand conditions		
Property	Summer	Winter
Sulfur content, wt %	1.36	1.36
Gravity, °API	31.2	31.3

Compared with summer, winter ethanol for higher ethanol demand conditions has a \$0.02 per gallon per barrel advantage in the refiner value difference relative to gasoline. So the increase in ethanol demand (32 percent) is large. Most of the increase in ethanol demand occurs in the production of CG with ethanol, with a large decrease in production of CG with low ether content. There is a 6 percent increase in production of distillates, while gasoline (excluding ethanol) production decreases nearly 1 percent. There is decreased utilization of reformers, which produce gasoline components and hydrogen. With increased requirements for distillate desulfurization, investment is required in hydrogen production capacity.

8.4 CALIFORNIA

Summer and winter summaries for gasoline properties, gasoline blendstocks, key process balances, investment, and crude quality are shown for reference conditions for California refineries in Tables 62 through 66. Previously discussed Table 23 shows the specifications for CARB RFG. For six of the eight standards, a refiner may choose either the "flat" limit of the "averaging" limit. The flat limit applies to every batch of finished gasoline. The averaging limit allows specific batches to exceed the flat limit as long as the fuel produced over a 180 day period meets the averaging limit and never exceeds the cap limit. The averaging specifications give refiners more blending options and help control operating costs. To ensure that the cap is not exceeded, a refiner that chooses the averaging method may produce gasoline for which average property values are considerably cleaner than the averaging specification.

As an alternative to flat or averaging limits, refiners can make their own changes to the specifications if they can show that emission effects are equivalent to those of the limits. Refiners must use a Predictive Model developed by CARB or an emissions test program to demonstrate the equivalency.

The choices among flat, averaging, cap, and Predictive Model alternatives are reflected in the CARB RFG qualities reported in the 1996 API/NPRA (1997) survey, and ORNL-RYM specifications for California gasolines are based on this survey.

The ethanol demand results for California have greater uncertainty than other regions because data for premises are limited; blending values had to be re-estimated in ORNL-RYM; and gasoline and diesel fuel specifications are very severe, which pushes ORNL-RYM to its present analytical limits. Furthermore, process sophistication for California refineries may be underestimated in the current version of ORNL-RYM, as suggested by the unanticipated investment in aromatics recovery in Table 65.

Modeled RFGs pass the Predictive Model tests for averaging. However, based on the EPA Complex Model for emissions, there can be a loss of emissions quality. In the study cases, TAP emissions can increase by up to 3 percent and NOx emissions can increase as much as 2 percent. If additional specifications were adopted to control TAP and NOx increases specifically due to ethanol/ETBE, the demand for ethanol in California could be somewhat lower than estimated.

Table 62. Gasoline properties in California for year 2010 reference conditions

	Summer				Winter			
	CG		CARB RFG		CG		CARB RFG	
	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal
Volume, MBD	0	152	484	430	82	40	102	755
Octane, (R+M)/2		88.7	88.8	88.8	88.6	88.6	88.7	88.7
RVP, psi		8.5 ^a	6.8	6.8	11.8	11.8	11.8	11.8
Aromatics, vol %		18.9	20.1	23.0	31.2	32.6	23.0	17.7
Benzene, vol %		0.75	0.55	0.55	0.75	0.75	0.55	0.55
Olefins, vol %		11.7	3.9	3.9	11.7	11.7	3.9	3.9
Sulfur, ppm		117	20	20	117	117	20	20
T50, °F		200	179	195	169	170	170	170
T90, °F		327	303	301	326	332	302	301
Oxygen, wt %		3.50	2.20	2.20	0.24	3.50	2.06	2.13
Specific gravity		.7460	.7322	.7489	.7420	.7492	.7249	.7269
California Predictive Model (6/98), Averaging			Pass	Pass			Pass ^b	Pass ^b
^a CG, which is produced for export to other regions, has a 1 psi RVP waiver for blends containing 10 percent ethanol. ^b With RVP set to default 7 psi.								

Table 63. Gasoline blendstocks in California for year 2010 reference conditions

Blendstock	Summer				Winter			
	CG		CARB RFG		CG		CARB RFG	
	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal	With ethers	With ethanol @ \$.65/gal
Butane					7.4	7.0	7.6	6.8
Reformate			40.4	23.2	35.3	5.8	29.3	22.6
Straight run naphtha			9.2		14.0	6.0	20.4	0.8
C5+ isomerate		9.1	2.4	7.0				7.1
FCC naphtha		28.6	6.7	11.5	41.5	19.6	3.3	10.5
Desulfurized FCC naphtha		36.1		14.1	0.3	40.5	3.6	12.9
Coker naphtha								
Hydrocrackate		7.7	11.2	30.1		9.6	15.3	18.7
Alkylate		9.0	16.3	8.1		1.9	7.4	15.1
Polymer gasolines		0.1						
Dimate								
Ethanol		9.4		5.9		9.5		5.6
ETBE			12.6		1.5		8.2	
MTBE								
Natural gasoline								
Pyrolysis gasoline								
Other			1.3				4.9	

Table 64. Hydrogen balance for California for year 2010 reference conditions

Entry at top of cell is fuel oil equivalent barrels of hydrogen per day
(minus sign indicates consumption)

Entry at bottom of cell is process unit utilization
(calendar rate divided by stream day capacity ^a x 100 percent)

Process	Summer	Winter
Naphtha hydrotreating	-2889 (93)	-2801 (89)
FCC naphtha desulfurization	-274 (new capacity)	-317 (new capacity)
Distillate desulfurization	-8269 (78)	-7054 (65)
FCC feed hydrofining	-8978 (77)	-8509 (73)
Gas oil hydrocracking	-46188 (87)	-38012 (69)
Reforming	+12815 (77)	+13068 (78)
C4 isomerization	-21 (89)	-20 (85)
C5/C6 isomerization	-114 (64)	-111 (62)
Ether production	-123 (87)	-114 (81)
Hydrogen production	+54683 (72)	+44523 (58)
Hydrogen to fuel and losses	-641	-653

^aFor comparability of summer and winter utilization, stream day capacity equals current in-place capacity plus announced construction.

Table 65. Process capacity additions in California for year 2010 reference conditions ^a		
Process ^b	Summer ^c	Winter ^d
Crude distillation	22	
Solvent deasphalting	21	
Naphtha hydrotreating	6	
FCC naphtha desulfurization	16	4
Aromatics recovery	163	18
\$Million	1013	81
^a Thousand barrels per day. ^b Investment decisions are based on a 15% DCF return on investment. ^c Summer capacity is current in-place plus announced construction plus investment from column 2. ^d Winter capacity is summer capacity plus investment .		

Table 66. Quality of crude oil processed in California for year 2010 reference conditions		
Property	Summer	Winter
Sulfur content, wt %	1.37	1.44
Gravity, °API	24.5	24.7

9. PRELIMINARY INDUSTRY REVIEW COMMENTS

Petroleum refining industry reviewers were asked to provide comments on a summary of Phase 1 ethanol demand studies. Reviewer comments and the italicized responses follow.

9.1 SUNOCO (King 1998)

1. A \$0.36 per gallon refiner value must assume a lower ethanol production cost than corn based product. Is a technology/commercialization breakthrough seen for biomass based ethanol production?

In its review of the potential of ethanol from lignocellulosic biomass, the National Renewable Energy Laboratory (NREL) evaluated cost reductions from improved ethanol producing strains, improved cellulase enzymes, and from higher carbohydrate composition biomass. NREL concluded that with process technology improvements, ethanol can be produced for \$0.75 to \$0.85 cents per gallon (Glassner and Wooley 1998). For those cost projections, lower-than-current tax exemptions would be required to realize a \$0.36 per gallon refiner value.

2. The Phase 2 RFG emissions impact on ethanol demand for summer RFG is real.
3. The paper indicates that as ethanol demand increases, the requirement for high quality gasoline blendstocks decreases. If other environmental fuel requirements exist, e.g., sulfur standards, RFG expansion, these high quality gasoline blendstocks will still be required. It's unlikely that refiners would cut production.

For the premised conditions, the requirement for high quality gasoline blendstocks decreases. However, sensitivity cases confirm the review comment. In the low sulfur gasoline sensitivity case illustrated in Figure 32, higher sulfur gasoline blendstocks (e.g., FCC naphthas) are being upgraded or displaced by ethanol, while high quality low sulfur blendstocks are retained or increased. Figure 29 confirms that RFG expansion depresses ethanol demand.

4. Is it reasonable to assume that ethanol production would increase eightfold, over 60 percent annual growth rate, from 1997 to 2010? Few products have been able to sustain this growth rate.

The ethanol demand curves are estimated for an arbitrary range of ethanol value/volume for convenience in examining supply and demand balance in future years, possibly with different tax incentive policies. In the demand analysis, no presumption is made about the likely level of ethanol production. The DOE reference case for growth of production of cellulosic ethanol is shown in Table 67 (Nguyen 1998). If it is assumed that corn ethanol production is constant (1.4 BGY), then the annual growth rate is 11 percent for total ethanol production during the period from 1997 (1.4BGY) to year 2010 (5.4 BGY).

Table 67. DOE reference case for growth of production of cellulosic ethanol (Nguyen 1998)		
Year	Incremental million gallons per year	Total million gallons per year
2000		0
2001	6	6
2002	20	26
2003	24	50
2004	50	100
2005	500	600
2006	600	1200
2007	600	1800
2008	600	2400
2009	600	3000
2010	1000	4000
2011	1000	5000
2012	1000	6000
2013	1000	7000
2014	1000	8000
2015	500	8500
2016	500	9000
2017	500	9500
2018	500	10000
2019	500	10500
2020	500	11000

5. It could be helpful to review CO and RFG areas of the United States, perhaps in an appendix.

Carbon monoxide nonattainment areas and RFG program areas are listed in Appendix A.

6. The study assumes no logistics impediments for this ethanol growth. Given that most ethanol is now terminal blended and consumed close to Midwest ethanol plants, a significant investment in transportation and logistic facilities would have to occur to "spread around" the increased ethanol.

Actually, the study assumes that ethanol handling and logistics costs are 10 cents per gallon, which is within the range of cost estimates reported by Anderson et al. (1988) and Czeskleba (1993). Anderson et al. (1988) estimate that handling and logistics costs could be as high as 24 cents per gallon (in 1988 dollars) for a national mandate with introduction of alcohol into anhydrous pipeline systems. The ethanol demand study presumes that modeled refineries can produce subgrade gasolines for shipment to blenders who add optimal volumes of ethanol to produce finished gasoline.

7. How much of the increased demand is related to high world oil prices and high MTBE prices? A case at "reference" oil and MTBE prices could show the unique impact of the \$0.36 ethanol value. Again, refinery material balances would dramatically change at this low ethanol value.

Since the premised MTBE price is a function of oil and gas prices (MATHPRO 1995), it is not possible to separate these effects in the cases examined. Figure 30 suggests that ethanol demand in PADD III would be very high with MTBE value minus ethanol value (\$0.36) at \$0.77. Figure 26 shows that ethanol demand in PADD II would be very high with refiner gasoline value minus ethanol (\$0.36) value at \$0.47.

8. The ability of vehicles to perform at 6 percent oxygen, 17 percent ethanol, seems at odds with information from auto manufacturers.

The 6 percent oxygen premise is based on a report suggesting that modern vehicles can generally perform adequately with oxygen levels of 5 to 6 weight percent (EEA). Follow-up consideration of any gasoline quality change, including a change in the oxygen specification, would rely on guidance of both automakers and refiners. Automakers have expressed concerns about the adverse effect of ethanol on hot driveability. They are also concerned about maintaining precise control of the air/fuel ratio in future vehicles. Increasing the ethanol concentration in gasoline blends will make this control more difficult due to the increased range of oxygen in the in-use vehicles' fuel tanks.

9. Concerning refinery impacts and distillate processing investment decreasing, is this an avoided future investment or a creation of excess capacity?

Some investment in distillate processing can be avoided.

10. Your greenhouse gas emission impacts seem more reasonable than other claims about ethanol.

Because of different viewpoints on greenhouse gas benefits, a greenhouse gas analysis is not presented in this final report.

11. 1996 is an atypical year for demonstrating plausibility of results because of the corn price spike that year.

A revised demonstration of plausibility of model performance is shown for 1997 in Figure 26.

9.2 MARATHON ASHLAND PETROLEUM LLC (Leister 1998)

1. The key findings are all reasonable given the starting assumptions and modeling constraints, with the exception of the greenhouse gas decrease. Most of the studies I have seen can only reach the conclusion that greenhouse gases decrease if a large portion of the carbon dioxide produced during the ethanol production process is assigned to the production byproducts and not the ethanol. Since this byproduct carbon dioxide is produced, in reality the cellulosic ethanol process has a net gain in carbon dioxide. Also ethanol has a higher carbon to heat of combustion ratio than gasoline so it makes more carbon dioxide when burned.

Because of different viewpoints on greenhouse gas benefits, a greenhouse gas analysis is not presented in this final report.

2. The projected ethanol demand are plausible if ethanol can be delivered to terminals throughout the U.S. at a value of \$0.36 per gallon. At such a cheap price all possible gasoline should contain ethanol and ethanol would be competitive with methanol in the manufacture of ethers. However, historically transportation costs have always limited ethanol distribution. To reduce feedstock transportation costs, ethanol production has typically been located close to the feedstock sources. These unfortunately have not been close to most of the major areas for gasoline demands. Since ethanol is typically moved by tanker truck or rail car, it is fairly expensive to move and at some distance it is no longer competitive to transport ethanol for gasoline blending. While I am not an expert of cellulosic ethanol manufacture, it is my understanding that most of the production would be in the west and possibly southeast. This cellulosic ethanol should experience similar transportation cost impacts to corn ethanol. Probably the best way to model this is to use tiers of demand which represent demands within certain radii of the expected centers of ethanol production. Each of these tiers would then carry its own transportation cost penalty.

The simplifying assumption in the study is that ethanol handling and logistics costs in refining/blending are 10 cents per gallon. The study presumes that modeled refineries can produce subgrade gasolines for shipment to blenders who add optimal volumes of ethanol to produce finished gasoline.

3. The use of the same ethanol production costs in years 2000-2025 is probably an oversimplification. No one expects the costs of cellulosic ethanol to be \$0.36 per gallon in 2000. The prices in future years should reflect a learning curve that approaches the \$0.36 per gallon level in 2010, or whenever experts deem likely.

The demand curves are estimated for an arbitrary range of ethanol values for convenience in examining supply and demand balance in future years, possibly with different tax incentive policies. In the demand analysis, no presumption is made about the likely cost of ethanol production.

4. Ethanol will continue to be drawn to those locations which provide subsidies in addition to the Federal subsidy. The model should recognize this.

Except for constraints on blending concentrations, the ethanol demand study is subsidy-blind. The demand curves are expressed as relationships between ethanol volume and refiner value.

5. In RFG production, ethanol competes with MTBE in RFG blending and with methanol as an ether unit feedstock. If summer RFG doesn't use much ethanol, MTBE and methanol prices may rise to the point where ethanol is used in RFG with short transportation distances and/or subsidies. It is possible that the Chicago area, low transportation costs and the Illinois ethanol subsidy plus high methanol/MTBE prices may allow ethanol to compete in RFG summer production.

Figure 7, which illustrates ORNL-RYM's estimate of oxygenate usage patterns in PADD II, is consistent with this reviewer comment. In Figure 7, as the refiner value of ethanol falls, the value of MTBE increases relative to ethanol.

6. The 9 percent increase in gasoline price from 1996 to 2000 seems a bit optimistic but probably doesn't have a significant impact on the study. However, I don't understand the derivation of the 23 percent increase in the refiner value of ethanol for the same period. Typically outside of RFG blending, ethanol is valued at gasoline cost plus its octane benefit. At 23 cents per gallon above gasoline, the 2000 ethanol value represents close to 1 cent per octane number, double the 1996 value. This is too high and should be lowered to the 1996 differential.

The reviewer comment refers to an inappropriate comparison of recent ethanol demand for gasoline blending with a backcast ethanol demand curve for the nation. A more appropriate comparison would be for the existing PADD II markets for ethanol-containing gasolines. When demand is expressed in terms of the difference in gasoline and ethanol values, as shown in Figure 26, the ORNL-RYM ethanol demand estimate for PADD II (backcast) matches very closely the actual demand for ethanol in PADD II in the summer of 1997. It is important to keep in mind that backcasting invites errors because there are differences in the premises for year 2010 versus actual conditions in 1997. Furthermore, there is uncertainty about agreement between backcast and actual ethanol demand because the demand curve is very elastic, and Midwestern state incentives for ethanol may not be accurately represented.

7. One possible inconsistency in this study, is that if the volumes of ethanol discussed are put into gasoline, the cost for the hydrocarbon portion of the gasoline is likely to drop rather than increase. Of course this would lower the value of ethanol blending.

The hydrocarbon price response, discussed in Section 10.3, appears to have a rather small effect on ethanol demand.

8. The final point is that since ethanol blending at the 10 percent levels results in a 3 to 4 percent loss in fuel economy, the addition of these large volumes of ethanol would cause some increase in total demand.

In the case studies, the fuel economy effect has been taken into account by increasing volume production as fuel economy decreases. The parametric demand curves are generated from a case

study with high ethanol use and there is a fuel economy correction for greater ethanol demand. For lesser ethanol demand, the volume production of gasoline can be slightly biased on the high side, and this introduces a second-order bias on the high side for ethanol demand. As discussed earlier, the case study demand estimates for ethanol agree very well with the parametric demand curves, and the biases appear to be insignificant.

9.3 EFFECT OF HYDROCARBON PRICE RESPONSE ON ETHANOL DEMAND

One concern of industry reviewers is that if the volumes of ethanol discussed are put into gasoline, the cost for the hydrocarbon portion of the gasoline is likely to drop rather than increase. A lower hydrocarbon cost would depress ethanol blending.

The long-term price elasticity effect has been investigated, and Figure 39 shows that this effect does not significantly change the original national ethanol demand curve. For the ethanol demand curve with price response, it is assumed that there is a 0.3 percent decrease in world oil price with 1 percent decrease in U.S. imports. Details of the price response calculations are shown in an example in Appendix D.

Fig. 39. Ethanol demand and price responsiveness for U.S. gasoline production and finishing in year 2010

10. CONCLUSIONS

Regional ethanol demand for gasoline production and finishing has been estimated with ORNL-RYM, and regional demands have been scaled to national demand. Figure 40 compares the national demand curves of ORNL-RYM with curves of MATHPRO, INC (1995). The figure shows that the ORNL-RYM curve for reference conditions is bracketed by the MATHPRO curves for mid and high oil price scenarios, but the ORNL-RYM curve for higher ethanol demand conditions is higher than the MATHPRO curves. The ORNL-RYM study assumes that the national RFG share of total gasoline production is 30 percent, whereas MATHPRO assumes an RFG production share of 50 percent. The difference in RFG production share assumptions may explain ORNL-RYM's higher ethanol demand estimates. These studies have not estimated the potential demand for ethanol in imported gasolines, which account for about 4 percent of gasoline supplied to U.S. consumers.

The sensitivity of ethanol demand to RFG production share is among the key findings of the ORNL-RYM study.

1. Annualized ethanol demand is higher with a lower share of RFG.
2. For regions outside California, future summer ethanol demand is dominated by CG because (1) limits on emissions of VOCs make summer RFG difficult to produce with high vapor pressure oxygenates like ethanol, and (2) ethanol's attractiveness in CG is enhanced by the 1 psi RVP waiver for 10 percent ethanol blends.
3. While RVP advantages disappear for winter CG, total ethanol used in winter RFG is limited by the RFG share.
4. In California, future summer ethanol demand is dominated by ETBE and ethanol blended to RFG. Relatively less ethanol is used in CG because the RFG production share is very high. During the winter, there is a significant increase in use of ethanol in RFG, as ethanol displaces lower-RVP ETBE.
5. Expanded investment options for new refinery processing technologies have negligible effects on ethanol demand.
6. Requirements for high quality gasoline blendstocks can fall as ethanol is added to gasoline, with a decrease in utilization of process units which produce these blendstocks. Some capacity can become available for distillate processing, and investment in distillate processing can decrease. Sensitivity cases for more stringent gasoline specifications, as in low sulfur gasoline, show that higher sulfur gasoline blendstocks will be upgraded or displaced by ethanol, while high quality low sulfur blendstocks are retained or increased.
7. A higher oxygen specification (6 wt percent maximum) for gasoline could increase ethanol demand by as much as 16 percent in PADD II. Follow-up consideration of any gasoline quality change, including a change in the oxygen specification, would rely on guidance of both

Fig. 40. Comparison of estimates of U.S. ethanol demand for gasoline production in year 2010

automakers and refiners. Automakers have expressed concerns about ethanol's potential adverse effects on driveability and air/fuel control.

8. A requirement for LSG could substantially increase the demand for ethanol over a significant range of refiner value for ethanol.
9. A VOC specification waiver for ethanol-containing RFGs could result in a significant increase in national ethanol demand.
10. A correction of the TAP specification to account for evaporative and exhaust emissions of MTBE has virtually no effect on ethanol demand in PADD II.
11. There is a significant increase in ethanol demand when the octane specification for gasoline is increased by 1 number.
12. For a given demand level, the value of ethanol estimated with a more rigorous Ratio-constrained version of ORNL-RYM is 6 percent higher than the original demand curve.
13. Ethanol demand is essentially the same with EIA data from different annual outlooks for energy markets.

The key findings lead to two general conclusions. First, the future demand for ethanol in gasoline production could be substantial as the refiner/blender value of ethanol decreases relative to the value of gasoline. Second, changes in gasoline specifications could further increase ethanol demand.

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APPENDIX A: CARBON MONOXIDE NONATTAINMENT AND REFORMULATED GASOLINE PROGRAM AREAS

CO Nonattainment State/Area/County Report

As of August 10, 1998

ALASKA (Region X)
Anchorage, AK (Serious)
 Anchorage Ed (P)
Fairbanks, AK (Serious)
 Fairbanks Ed (P)

ARIZONA (Region IX)
Phoenix, AZ (Serious)
 Maricopa Co (P)
Tucson, AZ (Not Classified)
 Pima Co (P)

CALIFORNIA (Region IX)
Los Angeles South Coast Air Basin, CA (Serious)
 Los Angeles Co (P)
 Orange Co
 Riverside Co (P)
 San Bernardino Co (P)

COLORADO (Region VIII)
Colorado Springs, CO (Moderate $\leq$ 12.7ppm)
 El Paso Co (P)
 Teller Co (P)
Denver-Boulder, CO (Serious)
 Adams Co (P)
 Arapahoe Co (P)
 Boulder Co (P)
 Denver Co
 Douglas Co (P)
 Jefferson Co (P)
Fort Collins, CO (Moderate $\leq$ 12.7ppm)
 Larimer Co (P)
Greeley, CO (Not Classified)
 Weld Co (P)
Longmont, CO (Moderate $\leq$ 12.7ppm)
 Boulder Co (P)
 Weld Co (P)

CONNECTICUT (Region I)
New Haven-Meriden-Waterbury, CT (Not Classified)
 Fairfield Co (P)
 Litchfield Co (P)

CO Nonattainment State/Area/County Report (Continued)

New Haven Co

New York-N. New Jersey-Long Island, NY-NJ-CT (Moderate > 12.7ppm)

Fairfield Co (P)

Litchfield Co (P)

IDAHO (Region X)

Boise-Northern Ada County, ID (Not Classified)

Ada Co (P)

INDIANA (Region V)

East Chicago, IN (Not Classified)

Lake Co (P)

Indianapolis, IN (Not Classified)

Marion Co (P)

MASSACHUSETTS (Region I)

Lowell, MA (Not Classified)

Middlesex Co (P)

Springfield, MA (Not Classified)

Hampden Co (P)

Waltham, MA (Not Classified)

Middlesex Co (P)

Worcester, MA (Not Classified)

Worcester Co (P)

MICHIGAN (Region V)

Detroit, MI (Not Classified)

Macomb Co (P)

Oakland Co (P)

Wayne Co (P)

MINNESOTA (Region V)

Minneapolis-St Paul, MN (Moderate <= 12.7ppm)

Anoka Co

Carver Co (P)

Dakota Co (P)

Hennepin Co

Ramsey Co

Scott Co (P)

Washington Co (P)

Wright Co (P)

MISSOURI (Region VII)

St Louis, MO (Not Classified)

St Louis

St Louis Co (P)

CO Nonattainment State/Area/County Report (Continued)

MONTANA(Region VIII)
Billings, MT (Not Classified)
Yellowstone Co (P)
Great Falls, MT (Not Classified)
Cascade Co (P)
Missoula, MT (Moderate $\leq$ 12.7ppm)
Missoula Co (P)

NEVADA(Region IX)
Lake Tahoe Nevada (Not Classified)
Carson City (P)
Douglas Co (P)
Washoe Co (P)
Las Vegas, NV (Serious)
Clark Co (P)
Reno, NV (Moderate $\leq$ 12.7ppm)
Washoe Co (P)

NEW HAMPSHIRE(Region I)
Manchester, NH (Not Classified)
Hillsborough Co (P)
Nashua, NH (Not Classified)
Hillsborough Co (P)

NEW JERSEY(Region II)
New York-N. New Jersey-Long Island, NY-NJ-CT (Moderate $>$ 12.7ppm)
Bergen Co

Essex Co
Hudson Co
Passaic Co (P)
Union Co

NEW YORK(Region II)
New York-N. New Jersey-Long Island, NY-NJ-CT (Moderate $>$ 12.7ppm)
Bronx Co
Kings Co
Nassau Co
New York Co
Queens Co
Richmond Co
Westchester Co

OREGON(Region X)
Grants Pass, OR (Moderate $\leq$ 12.7ppm)
Josephine Co (P)
Klamath Falls, OR (Moderate $\leq$ 12.7ppm)
Klamath Co (P)

CO Nonattainment State/Area/County Report (Continued)

Medford, OR (Moderate $\leq$ 12.7ppm)
Jackson Co (P)

Salem, OR (Not Classified)
Marion Co (P)
Polk Co (P)

PENNSYLVANIA (Region III)
Pittsburgh, PA (Not Classified)
Allegheny Co (P)

TEXAS (Region VI)
El Paso, TX (Moderate $\leq$ 12.7ppm)
El Paso Co (P)

UTAH (Region VIII)
Ogden, UT (Moderate $\leq$ 12.7ppm)
Weber Co (P)
Provo, UT (Moderate $>$ 12.7ppm)
Utah Co (P)
Salt Lake City, UT (Not Classified)
Salt Lake Co (P)

WASHINGTON (Region X)
Spokane, WA (Serious)
Spokane Co (P)
Yakima, WA (Not Classified)
Yakima Co (P)

(P) : A portion of the county is located within the area and is designated nonattainment.

This is not an official list CO of nonattainment areas. See the Code of Federal Register (40 CFR Part 81) and pertinent Federal Register notices for legal lists and boundaries.

[Carbon Monoxide] [Green Book Home Page]

List of Reformulated Gasoline Program Areas
July 2, 1998

[Required Areas] [Opt-In Areas] [Opt-Out Areas]

Clean Air Act

Required Areas:

LOS ANGELES - South Coast Air Basin, South East Desert, Ventura, CA

- Los Angeles County, CA
- Ventura County, CA
- Orange County, CA
- San Bernardino County (partial), CA
- Riverside County (partial), CA

SAN DIEGO County, CA

- San Diego County, CA

HARTFORD - New Haven - Waterbury, CT

- Hartford County (partial), CT
- Litchfield County (partial), CT
- Middlesex County (partial), CT
- New London County (partial), CT
- New Haven County (partial), CT
- Tolland County (partial), CT

NEW YORK - Northern New Jersey - Long Island - Connecticut area, NY-NJ-CT

- Fairfield County, CT
- Litchfield County, (partial), CT
- New Haven County (partial), CT
- Bergen County, NJ
- Essex County, NJ
- Hudson County, NJ
- Hunterdon County, NJ
- Middlesex County, NJ
- Monmouth County, NJ
- Morris County, NJ
- Ocean County, NJ
- Passaic County, NJ
- Somerset County, NJ
- Sussex County, NJ
- Union County, NJ
- Bronx County, NY
- Kings County, NY
- Nassau County, NY
- New York County, NY
- Orange County, NY
- Putnam, NY
- Queens County, NY
- Richmond County, NY

List of Reformulated Gasoline Program Areas (Continued)

- Rockland County, NY
- Suffolk County, NY
- Westchester County, NY

PHILADELPHIA - Wilmington - Trenton - Cecil County, MD area PA-NJ-DE-MD

- New Castle County, DE
- Kent County, DE
- Cecil County, MD
- Burlington County, NJ
- Camden County, NJ
- Cumberland County, NJ
- Gloucester County, NJ
- Mercer County, NJ
- Salem County, NJ
- Bucks County, PA
- Chester County, PA
- Delaware County, PA
- Montgomery County, PA
- Philadelphia County, PA

CHICAGO - Gary - Lake County, IL - Indiana - Wisconsin area

- Cook County, IL
- Du Page County, IL
- Kane County, IL
- Lake County, IL
- McHenry County, IL
- Will County, IL
- Grundy County, IL, (partial)
- Kendall County, IL, (partial)
- Lake County, IN
- Porter County, IN

BALTIMORE, MD

- Anne Arundel County, MD
- Baltimore County, MD
- Carroll County, MD
- Harford County, MD
- Howard County, MD
- The City of Baltimore, MD

HOUSTON - Galveston - Brazoria, TX

- Brazoria County, TX
- Chambers County, TX
- Fort Bend County, TX
- Galveston County, TX
- Harris County, TX
- Liberty County, TX
- Montgomery County, TX

List of Reformulated Gasoline Program Areas (Continued)

- Waller County, TX

MILWAUKEE - Racine, WI

- Kenosha County, WI
- Milwaukee County, WI
- Ozaukee County, WI
- Racine County, WI
- Washington County, WI
- Waukesha County, WI

SACRAMENTO, CA * (newly required area)

- El Dorado County (partial), CA
- Placer County (partial), CA
- Sacramento County, CA
- Solano County (partial), CA
- Sutter County (partial), CA
- Yolo County, CA

* Reclassification of Sacramento from Serious to Severe was effective June 1, 1995. RFG was required as of June 1, 1996.

"Opt-In" Areas (Voluntary)

CONNECTICUT, The Entire State 1

- Litchfield County (partial), CT
- Hartford County (partial), CT
- Middlesex County (partial), CT
- New London County (partial), CT
- Tolland County (partial), CT
- Windham County, CT

DELAWARE, The Entire State 1

Sussex nonattainment area

- Sussex County, DE

DISTRICT OF COLUMBIA

Washington, DC-MD-VA area (DC portion)

- Entire District of Columbia

KENTUCKY

Cincinnati-Hamilton KY-OH area (KY portion)

- Boone County, KY
- Campbell County, KY
- Kenton County, KY

Louisville, KY-IN area (KY portion)

- Jefferson County, KY
- Bullitt County (partial), KY
- Oldham County (partial), KY

List of Reformulated Gasoline Program Areas (Continued)

MAINE

- Knox & Lincoln nonattainment area
 - Knox County, ME
 - Lincoln County, ME
- Lewiston-Auburn nonattainment area
 - Androscoggin County, ME
 - Kennebec County, ME
- Portland nonattainment area
 - Cumberland County, ME
 - Sagadahoc County, ME
 - York County, ME

MARYLAND

- Washington, DC-MD-VA area (MD portion)
 - Calvert County, MD
 - Charles County, MD
 - Frederick County, MD
 - Montgomery County, MD
 - Prince Georges County, MD
- Kent & Queen Anne's nonattainment area
 - Queen Anne's County, MD
 - Kent County, MD

MASSACHUSETTS, The Entire State 1

- Boston-Lawrence-Worcester (E. MA)
 - Barnstable County, MA
 - Bristol County, MA
 - Dukes County, MA
 - Essex County, MA
 - Middlesex County, MA
 - Nantucket County, MA
 - Norfolk County, MA
 - Plymouth County, MA
 - Suffolk County, MA
 - Worcester County, MA
- Springfield (Western MA) nonattainment areas
 - Berkshire County, MA
 - Franklin County, MA
 - Hampden County, MA
 - Hampshire County, MA

NEW HAMPSHIRE

- Boston-Lawrence-Worcester, MA-NH nonattainment area (NH portion)
 - Hillsborough County, NH
 - Rockingham County, NH
 - Merrimack County, NH
 - Strafford County, NH

List of Reformulated Gasoline Program Areas (Continued)

NEW JERSEY, The Entire State 1

Allentown-Bethlehem-Easton area (NJ portion)

- Warren County, NJ

Atlantic City nonattainment area

- Atlantic County, NJ
- Cape May County, NJ

NEW YORK

Essex nonattainment area

- Dutchess County, NY
- Essex County (partial), NY

RHODE ISLAND, The Entire State

Providence nonattainment area

- Bristol County, RI
- Kent County, RI
- Newport County, RI
- Providence County, RI
- Washington County, RI

TEXAS

Dallas-Fort Worth nonattainment area

- Collin County, TX
- Dallas County, TX
- Denton County, TX
- Tarrant County, TX

VIRGINIA

Washington DC-MD-VA area (VA portion)

- 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

Richmond, VA nonattainment area

- Charles City County, VA
- Chesterfield County, VA
- Colonial Heights, VA
- Hanover County, VA
- Henrico County, VA
- Hopewell, VA
- Richmond, VA

Norfolk-Virginia Beach-Newport News area

List of Reformulated Gasoline Program Areas (Continued)

- Chesapeake, VA
- Hampton, VA
- James City County, VA
- Newport News, VA
- Norfolk, VA
- Poquoson, VA
- Portsmouth, VA
- Suffolk, VA
- Virginia Beach, VA
- Williamsburg, VA
- York County, VA.

"Opt-Out" Areas:

Note: These "Opt-Out" areas withdrew from the federal RFG program before it went into effect on January 1, 1995. See below for details.

MAINE

Hancock and Waldo Counties, ME

- Hancock County
- Waldo County

PENNSYLVANIA

Allentown - Bethlehem - Easton, PA

- Carbon County
- Lehigh County
- Northampton County

Altoona, PA

- Blair County

Erie, PA

- Erie County

Harrisburg - Lebanon - Carlisle, PA

- Cumberland County
- Dauphin County
- Lebanon County
- Perry County

Johnstown, PA

- Cambria County
- Somerset County

Lancaster, PA

- Lancaster County

Pittsburgh - Beaver Valley, PA

- Allegheny County
- Beaver County
- Fayette County

List of Reformulated Gasoline Program Areas (Continued)

- Washington County
 - Westmoreland County
 - Armstrong County
 - Butler County
- Reading, PA
- Berks County
- Scranton - Wilkes-Barre, PA
- Columbia County
 - Lackawanna County
 - Luzerne County
 - Monroe County
 - Wyoming County
- York, PA
- Adams County
 - York County
- Youngstown, OH - Warren, OH - Sharon, PA*
- Mercer, PA
- * Ohio counties have not opted-in.

NEW YORK

- Albany - Schenectady - Troy, NY
- Albany County
 - Greene County
 - Montgomery County
 - Rensselaer County
 - Saratoga County
 - Schenectady County

Jefferson County, NY

- Buffalo - Niagara Falls, NY
- Erie County
 - Niagara County

A proposed rule to remove the above "opt-out" areas from the requirements of the reformulated gasoline program was published June 14, 1995. [On January 1, 1995, a temporary exemption of the RFG requirements in these areas went into effect. On July 1, 1995 this stay was extended until the Agency took final action].

The final rule, published July 8, 1996 [61 FR 35673], formally removed these areas from the list of RFG covered areas and provided states with general opt-out procedures.

The July 8 final rule was superseded by a final rule published October 20, 1997 [62 FR 54552], revising the opt-out procedures.

List of Reformulated Gasoline Program Areas (Continued)

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ARIZONA

Phoenix nonattainment area
- Maricopa County (partial), AZ

Phoenix opted in the RFG program in 1997; retail stations were required to supply RFG by August 4, 1997.

In September 1997, the Governor of Arizona submitted an RFG opt-out petition for purposes of adopting a more stringent state RFG program in Phoenix.

EPA approved the opt-out petition which became effective on June 10, 1998.

[Reformulated Gasoline Page] [OMS Fuels Page] [OMS Home Page] [EPA homepage]
url: www.epa.gov/omswwww/rfgarea.htm
Updated 6 July 1998

APPENDIX B: SCALING FACTORS FOR ESTIMATION OF NATIONAL ETHANOL DEMAND

REFERENCE CONDITIONS

Based on crude distillation capacity, 90 percent of U.S. refinery capacity is included in the ethanol demand study for reference conditions. In scaling to a national level, the demand for ethanol has to be estimated for those areas not included in the study of reference conditions: PADD IV (Rocky Mountain area) and PADD V outside California (the West Coast area, excluding California).

The ratio of national production of CG to production of CG in PADDs I-III is 1.13 (DOE 1996c; DOE 1998; CEC 1998b). Thus the national estimate of ethanol demand in CG is $1.13 * (\text{ethanol demand for CG produced in PADDs I-III}) + \text{ethanol demand for CG produced in California}$.

Since the data sources report no RFG is production PADD IV or in PADD V outside California, the national estimate of ethanol demand in RFG is $1.0 * (\text{ethanol demand for RFG produced in PADDs I-III}) + \text{ethanol demand for RFG produced in California}$.

The scale up factors are almost the same for summer and winter seasons. With an estimated summer season of 5.5 months, annualized ethanol demand is $5.5/12 * (\text{summer demand}) + 6.5/12 * (\text{winter demand})$.

HIGHER ETHANOL DEMAND

Based on crude distillation capacity, 69 percent of U.S. refinery capacity is included in the ethanol demand study for higher ethanol demand conditions. In scaling to a national level, the demand for ethanol has to be estimated for those areas not included in the study of higher ethanol demand conditions: PADDs I, IV, and V.

The ratio of national production of CG to production of CG in PADDs II-III is 1.21 (DOE 1996c; DOE 1998). Thus the national estimate of ethanol demand in CG is $1.21 * (\text{ethanol demand for CG produced in PADDs II-III})$. The national estimate of ethanol demand in RFG is $2.83 * (\text{ethanol demand for RFG produced in PADDs II-III})$. The scale up factors are the same for summer and winter seasons. With an estimated summer season of 5.5 months, annualized ethanol demand is $5.5/12 * (\text{summer demand}) + 6.5/12 * (\text{winter demand})$.

APPENDIX C: MULTIYEAR FORECAST CALCULATIONS

For the component of demand due to ethanol blending in gasoline, the refinery model's ethanol demand curve for reference conditions in year 2010 has been extrapolated to demand curves for five-year intervals between years 2000 and 2025, using extrapolation factors for petroleum prices and gasoline supply derived from the *Annual Energy Outlook* (DOE 1996b). The ethanol value and demand relationships for year (2010 + i) are:

$$\text{Ethanol value}_{\text{year } 2010 + i} = (\text{Ethanol value}_{\text{year } 2010}) * (1 + \text{rate of growth of petroleum price})^i$$

$$\text{Ethanol value}_{\text{year } 2010 + i} = (\text{Ethanol value}_{\text{year } 2010}) * (1 + 0.01)^i$$

$$\text{Ethanol demand}_{\text{year } 2010 + i} = (\text{Ethanol demand}_{\text{year } 2010}) * (1 + \text{rate of growth of gasoline supply})^i$$

$$\text{Ethanol demand}_{\text{Year } 2010 + i} = (\text{Ethanol demand}_{\text{year } 2010}) * (1 + 0.008)^i$$

APPENDIX D: CALCULATION OF HYDROCARBON PRICE RESPONSE EFFECT ON ETHANOL DEMAND

For the ethanol demand curve with price response, it is assumed that there is a 0.3 percent decrease in world oil price with 1 percent decrease in U.S. imports (TMS 1998).

- (1) Fig. 26 suggests that ethanol demand is driven by [gasoline value minus ethanol value].
- (2) Premises: For the national demand curve, assume that ethanol volume versus [gasoline value minus ethanol value] does not change due to the hydrocarbon price response. Assume that ethanol displaces oil imports.
- (3) For each point on the ethanol demand curve, calculate:
 - (a) Effect of ethanol use on demand for oil imports. Example: For original ethanol demand of 10.18 BGY at \$0.357 per gallon, assume ethanol Btus (75,670/gal) displace crude oil Btus (131,800/gal). Therefore, the oil displaced is 5.85 BGY.
 - (b) Oil displaced as a percent of year 2010 oil imports (146.86 BGY, which includes crude and products). $5.85/146.86 \times 100 \text{ percent} = 3.98 \text{ percent}$.
 - (c) Oil price effect. $(3.98) \times (0.3 \text{ percent}) (\$0.544) = \$0.006/\text{gal}$, where \$0.544 is the year 2010 world oil price per gallon. Based on *Oil & Gas Journal* (1986), the gasoline price effect is $1.08 \times \text{the crude oil price effect} = 1.08 \times \$0.006/\text{gallon} = \$0.0065/\text{gal}$.
 - (d) Original [gasoline value minus ethanol value] = $\$0.777/\text{gal} - \$0.357/\text{gal} = \$0.420/\text{gal}$.
New [gasoline value minus ethanol value] = $\$0.777/\text{gal} - \$0.0065 - \$0.357/\text{gal} = \$0.414/\text{gal}$.
 - (e) New [gasoline value minus ethanol value] corresponds to a revised ethanol volume of 10.17 BGY, which is a demand shift of 0.01 BGY.
 - (f) If demand shift is large, iterate to convergence.

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