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Ethanol Demand in United States Regional Production of Oxygenate-limited Gasoline

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ACRONYMS AND ABBREVIATIONS

AEO	*Annual Energy Outlook*
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BGY	Billion gallons per year
CAAA	Clean Air Act Amendments of 1990
CG	Conventional gasoline
C4s	Butane and related 4-carbon molecules
DCF	Discounted cash flow
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EtOH	Ethanol
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
FY	Fiscal year
LSG	Low sulfur gasoline
M	Motor octane number
max	Maximum
MBD	Thousand barrels per day
MBCD	Thousand barrels per calendar 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
MTBE	Methyl tertiary butyl ether
NOx	Oxides of nitrogen
NPC	National Petroleum Council
NPRA	National Petroleum Refiners Association or National Petrochemical & Refiners Association
ORNL	Oak Ridge National Laboratory
OTT	Office of Transportation Technologies
PADD	Petroleum Administration for Defense District
ppm	Part per million
Prem	Premium
psi	Pounds per square inch
R	Research octane number
Reg	Regular
RFG	Reformulated gasoline
RVP	Reid vapor pressure
RYM	Refinery Yield Model
ST/CD	Short tons per calendar day
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
wt	Weight

ABSTRACT

Ethanol competes with methyl tertiary butyl ether (MTBE) to satisfy oxygen, octane, and volume requirements of certain gasolines. However, MTBE has water quality problems that may create significant market opportunities for ethanol. Oak Ridge National Laboratory (ORNL) has used its Refinery Yield Model to estimate ethanol demand in gasolines with restricted use of MTBE. Reduction of the use of MTBE would increase the costs of gasoline production and possibly reduce the gasoline output of U.S. refineries. The potential gasoline supply problems of an MTBE ban could be mitigated by allowing a modest 3 vol percent MTBE in all gasoline. In the U.S. East and Gulf Coast gasoline producing regions, the 3 vol percent MTBE option results in costs that are 40 percent less than an MTBE ban. In the U.S. Midwest gasoline producing region, with already high use of ethanol, an MTBE ban has minimal effect on ethanol demand unless gasoline producers in other regions bid away the local supply of ethanol. The ethanol/MTBE issue gained momentum in March 2000 when the Clinton Administration announced that it would ask Congress to amend the Clean Air Act to provide the authority to significantly reduce or eliminate the use of MTBE; to ensure that air quality gains are not diminished as MTBE use is reduced; and to replace the existing oxygenate requirement in the Clean Air Act with a renewable fuel standard for all gasoline. Premises for the ORNL study are consistent with the Administration announcement, and the ethanol demand curve estimates of this study can be used to evaluate the impact of the Administration principles and related policy initiatives.

EXECUTIVE SUMMARY

The Energy Policy Act of 1992 (the Act) outlined a national energy strategy that called for reducing the nation's dependency on petroleum imports. The Act directed the Secretary of Energy to establish a program to promote and expand the use of renewable fuels. The Office of Transportation Technologies (OTT) within the U.S. Department of Energy (DOE) has evaluated a wide range of potential fuels and has concluded that cellulosic ethanol is one of the most promising near-term prospects. Ethanol is widely recognized as a clean fuel that helps reduce emissions of toxic air pollutants. Furthermore, cellulosic ethanol produces less greenhouse gas emissions than gasoline or any of the other alternative transportation fuels being considered by DOE.

Most ethanol is now produced from corn. While some growth in the corn-based ethanol industry is anticipated, its expansion is constrained by the competing food uses of corn. DOE believes that cellulosic ethanol technology has the potential to significantly increase domestic ethanol production and is currently funding research to advance cellulosic ethanol conversion techniques. Cellulosic ethanol can be produced from agricultural residues and biocrops specifically designed for the energy market.

Ethanol has the potential to displace petroleum in two distinct markets. The blend market is characterized by gasoline/ethanol mixtures containing 10 percent or less ethanol by volume. The neat market is characterized by ethanol/gasoline mixtures containing 85 percent or more ethanol by volume. The blend market has significant advantages with respect to early market penetration. First, gasoline/ethanol blends can be used in all gasoline-powered automobiles and light trucks on the road today. Neat ethanol fuels require specially adapted engines and can be used in only a small percent of the current vehicle fleet. Second, ethanol blends are compatible with the existing retail infrastructure. Because of the need for separate service station tanks and pumps, neat ethanol fuels will require substantial infrastructure investments. Third, ethanol used in blends is valued as an octane enhancer and an oxygenate. Ethanol used in neat fuels will have to compete with gasoline on a mileage or energy content basis, but ethanol has only about two-thirds the energy content of gasoline.

Ethanol competes with methyl tertiary butyl ether (MTBE) to satisfy oxygen, octane, and volume requirements of certain gasolines. However, MTBE has water quality problems that may create significant market opportunities for ethanol. The use of MTBE in the reformulated gasoline (RFG) program has resulted in growing detections of MTBE in drinking water, with between 5 percent and 10 percent of community drinking water supplies in high oxygenate use areas showing at least detectable amounts of MTBE. There have been important debates about the air quality benefits and water quality problems of MTBE. In November, 1998, the

U.S. Environmental Protection Agency (EPA) Administrator appointed a Blue Ribbon Panel to investigate the air quality benefits and water quality concerns associated with oxygenates in gasoline. The Panel generally agreed that less MTBE should be used in the reformulated gasoline program. Given the Panel recommendations, the EPA Administrator announced that "We must begin to significantly reduce the use of MTBE in gasoline as quickly as possible without sacrificing the gains we've made in achieving cleaner air."

In support of the Office of Fuels Development in the DOE OTT, Oak Ridge National Laboratory (ORNL) has used its refinery yield model (ORNL-RYM) to estimate ethanol demand in gasolines with restricted use of oxygenates. ORNL-RYM is a linear program representing 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 a comprehensive set of gasoline properties, including formula and emissions standards required by the Clean Air Act Amendments of 1990.

If there is a mandated reduction of MTBE in gasoline, some MTBE could be replaced by high-octane, high toxicity, high-aromatics gasoline blendstocks. With current gasolines emitting less than the statutory limits for toxic air pollutants, it is possible that toxic air pollutants could increase with these high-aromatics replacement blendstocks. This study assumes that new regulations will not allow "toxics-backsliding" (no increase of toxics above recently observed levels). With toxics-backsliding not allowed, low toxicity blendstocks like alkylates are likely to be favored over high-aromatics replacement stocks.

Data for the study are based on information published by DOE, the U.S. Energy Information Administration, the National Petroleum Council, the National Petrochemical & Refiners Association, and industry journals. The study design is shown in Table S-1. Study cases estimate refinery demand curves for ethanol in a low sulfur gasoline world; with or without a partial or full ether ban; and with or without an oxygen content specification.

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 5 cents per gallon. Third, it is assumed that consumers are indifferent to ethanol blends, neither seeking nor avoiding these gasolines.

Ethanol demand is analyzed for gasoline production in Petroleum Administration for Defense District I (PADD I, the U.S. East Coast), PADD II (U.S. Midwest) and PADD III (U.S. Gulf Coast). These regions account for about 80 percent of U.S. gasoline production. Annualized ethanol demand curves for the regions are shown in Figs. S-1 and S-2.

Table S-1. Study case design

Case	1	2	3	4	5	6
General	Referenc e	3% vol max MTBE	3% vol max MTBE	Reference	Ether Ban	Ether Ban
Region	East/Gulf Coasts	East/Gulf Coasts	East/Gulf Coasts	Midwest	Midwest	Midwest
Year	2006	2006	2006	2006	2006	2006
Season	Sum	Sum	Win	Sum	Sum	Win
RFG oxygen wt%[a,b]	2.1-2.7	0-3.5(E) <0.5 (M)	0-3.5(E) <0.5 (M)	2.1-3.5	0-3.5	0-3.5
CG oxygen wt%[a]	0-2.7	0-3.5	0-3.5	0-3.5	0-3.5	0-3.5
Vol percent ethanol in CG[c]	N/A	10	10	10	10	10
Gasoline oxygenate	MTBE	EtOH MTBE	EtOH MTBE	EtOH MTBE	EtOH	EtOH
Gasoline pools[b]	CG-M CG-E RFG-M-R RFG-M-P RFG-E-R RFG-E-P	CG-M CG-E RFG-M-R RFG-M-P RFG-E-R RFG-E-P	CG-M CG-E RFG-M-R RFG-M-P RFG-E-R RFG-E-P	CG-M CG-E RFG-M-R RFG-M-P RFG-E-R RFG-E-P	CG-N CG-E RFG-N-R RFG-N-P RFG-E-R RFG-E-P	CG-N CG-E RFG-N-R RFG-N-P RFG-E-R RFG-E-P
RFG share	Current					
Economic premises	DOE Reference					
Ethanol cost	N/A	Vary	Vary	Vary	Vary	Vary
Other	Ratio-free refinery model/ low sulfur gasoline/ no toxics backsliding					

Fig. S-1. Annual ethanol demand with reduced MTBE in PADD I+III gasoline type production
Year 2006 - 3% max MTBE - 30 ppm sulfur in gasoline

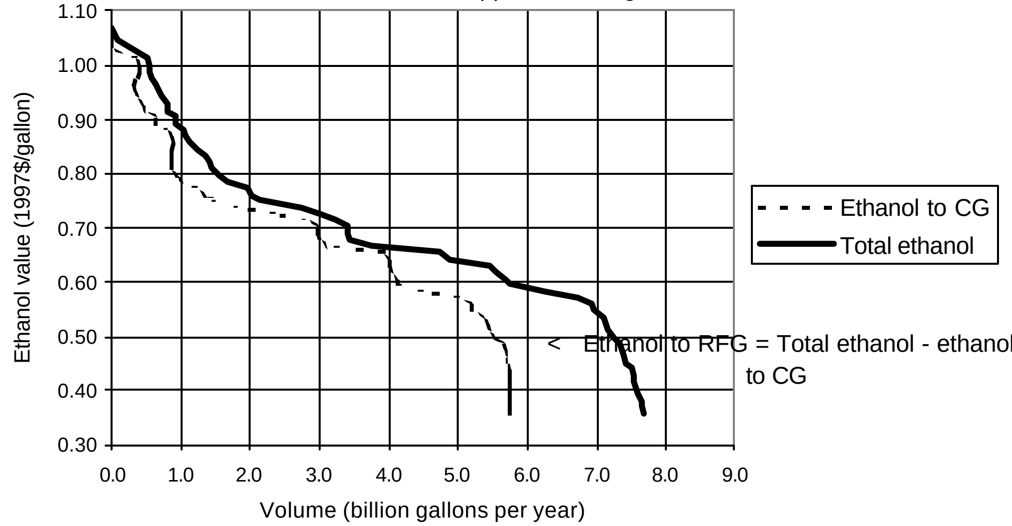
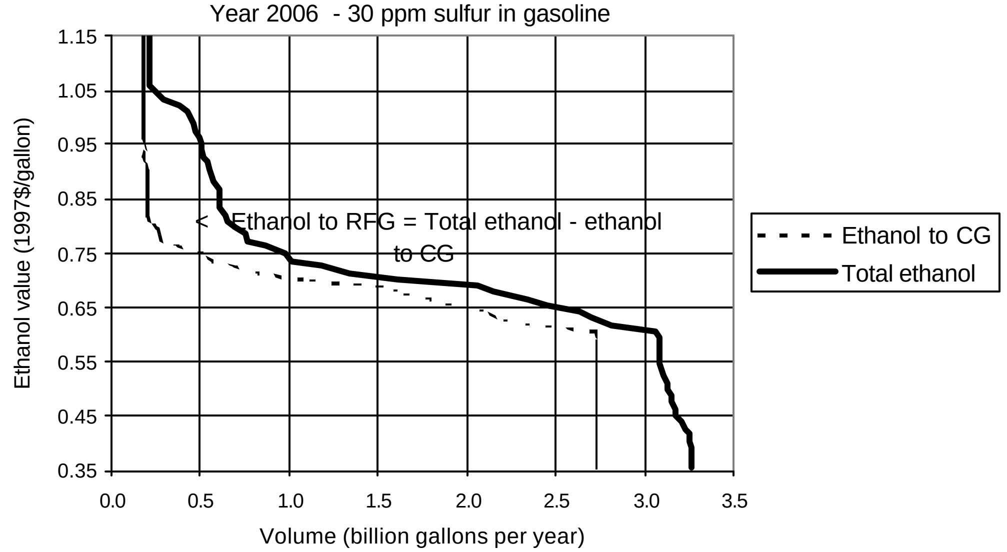


Fig. S-2. Annual ethanol demand with MTBE ban in PADD II gasoline type production
Year 2006 - 30 ppm sulfur in gasoline



[a]Oxygen content in ethanol-containing gasoline is restricted to current tax incentive levels.
[b]R=regular grade; P=premium grade; E=containing ethanol; M=containing MTBE; N=containing no oxygenate.
[c]With RVP waiver (affects summer CG), assume that summer and winter CG-E contains 10 percent ethanol.

Marginal cost results show that volatility limits make summer RFG more difficult to produce with high-Reid vapor pressure (RVP) oxygenates like ethanol. Ethanol's value in conventional gasoline (CG) is enhanced by the 1 pound per square inch RVP waiver for 10 percent ethanol blends, and CG is typically the source of greatest demand for ethanol over the range of ethanol values.

Reduction of the use of MTBE would increase the costs of gasoline production and possibly reduce the gasoline output of U.S. refineries. MTBE is the dominant oxygenate in RFG, and gasoline production has evolved to depend on the attractive octane and volatility characteristics of MTBE. DOE has reported that elimination of MTBE is equivalent to a loss of up to 5 percent of the U.S. gasoline supply, when the octane-yield trade-offs for the replacement blendstocks are taken into account.

The potential gasoline supply problems of an MTBE ban could be mitigated by allowing a modest 3 vol percent MTBE in all gasoline. In PADD I+III, a 3 vol percent MTBE option results in costs that are 40 percent less than an MTBE ban. Major contributors to increased costs for a ban of MTBE are control of octane, volatility, and prevention of backsliding of toxic air pollutant emissions.

With a drop in MTBE production, more C4s (butane and related 4-carbon molecules) become available. Absent conversion of MTBE plants to production technologies that utilize isobutylene, ethanol is the primary substitute for MTBE in the summer. However, in the winter, ethanol may have to compete with directly-blended C4s.

PADD II has the highest regional use of ethanol, which provides about 90 percent of the total oxygenate volume now blended to that region's gasoline. Furthermore, the production share of RFG in PADD II is relatively low. Consequently, over much of ethanol's value range, a reduction in MTBE does not substantially change ethanol demand in PADD II gasoline production. An MTBE ban in PADD II gasoline production results in a cost increase of only 0.3 cents per gallon of RFG.

The ethanol/MTBE issue gained momentum in March 2000 when the Clinton Administration announced that it would ask Congress to amend the Clean Air Act to provide the authority to significantly reduce or eliminate the use of MTBE; to ensure that air quality gains are not diminished as MTBE use is reduced; and to replace the existing oxygenate requirement in the Clean Air Act with a renewable fuel standard for all gasoline.

The premises for this ORNL study are consistent with the Administration announcement, and the ethanol demand curve estimates of this study can be used to evaluate the impact of the Administration principles and related policy initiatives.

1. INTRODUCTION

The Energy Policy Act of 1992 outlined a national energy strategy that called for reducing the nation's growing dependency on imported petroleum. Recognizing the need to develop alternative transportation fuels, the Act directed the Secretary of Energy to establish a program to promote and expand the use of renewable fuels. The Office of Transportation Technologies (OTT) within the U.S. Department of Energy (DOE) has evaluated a wide range of potential fuels and has concluded that cellulosic ethanol is one of the most promising near-term prospects. Ethanol is a proven and publicly accepted fuel that has been used in the United States since the 1970s. It is widely recognized as a clean fuel that helps reduce emissions of toxic air pollutants. Furthermore, cellulosic ethanol produces less greenhouse gas emissions than gasoline, or for that matter, any of the other alternative transportation fuels being considered by DOE.

About 1.5 billion gallons per year (BGY) of ethanol are currently used in gasoline blends. Most of this ethanol is now produced from corn. While some growth in the corn-based ethanol industry is anticipated, its expansion is constrained by the competing uses of corn as a food crop. DOE believes that cellulosic ethanol technology has the potential to significantly increase domestic ethanol production and is currently funding research to advance cellulosic ethanol conversion techniques. Cellulosic ethanol can be produced from agricultural residues and genetically engineered biocrops specifically designed for the energy market.

Ethanol has the potential to displace petroleum in two distinct markets. The blend market is characterized by gasoline/ethanol mixtures containing 10 percent or less ethanol by volume. The neat market is characterized by ethanol/gasoline mixtures containing 85 percent or more ethanol by volume.

The blend market has significant advantages with respect to early market penetration. First, gasoline/ethanol blends can be used in all gasoline-powered automobiles and light trucks on the road today. Neat ethanol fuels require specially adapted engines and can be used in only a small percent of the current vehicle fleet. Second, ethanol blends are compatible with the existing service station infrastructure. Because of the need for separate service station tanks and pumps, neat ethanol fuels will require substantial infrastructure investments. Third, ethanol used in blends is valued as an octane enhancer and an oxygenate and not just for its energy content. Ethanol used in neat fuels will have to compete with gasoline on a mileage or energy content basis. Ethanol has about two-thirds the energy content of gasoline (Andress and Hadder, 1999).

Ethanol competes with methyl tertiary butyl ether (MTBE) to satisfy oxygen, octane, and volume requirements of certain gasolines. However, MTBE has water quality problems that may create significant market opportunities for ethanol. The use of MTBE in the reformulated gasoline (RFG) program has resulted in growing detections of MTBE in drinking water, with between 5 percent and 10 percent of community drinking water supplies in high oxygenate use areas showing at least detectable amounts of MTBE. The great majority of these detections to date have been well below levels of public health concern, with approximately one percent rising to levels above 20 parts per billion. Detections at lower levels have, however, raised consumer taste and odor concerns that have caused water suppliers to stop using some water supplies and to incur costs of treatment and remediation. Private wells have also been contaminated, and these wells are less protected than public drinking water supplies and not monitored for chemical contamination. There is also evidence of contamination of surface waters, particularly during summer boating seasons.

The major source of groundwater contamination appears to be releases from underground gasoline storage systems. These systems have been upgraded over the last decade, likely resulting in reduced risk of leaks. However, approximately 20 percent of the storage systems have not yet been upgraded, and there continue to be reports of releases from some upgraded systems, due to inadequate design, installation, maintenance, and/or operation. In addition, many fuel storage systems (e.g., farms, small above-ground tanks) are not currently regulated by the U.S. Environmental Protection Agency (EPA). Beyond groundwater contamination from underground storage tank sources, the other major sources of water contamination appear to be small and large gasoline spills to ground and surface waters, and recreational water craft, particularly those with older motors, releasing unburned fuel to surface waters (U.S. EPA, 1999). There have been important debates about the air quality benefits and water quality problems of MTBE:

> In November, 1998, EPA Administrator Carol M. Browner appointed a Blue Ribbon Panel to investigate the air quality benefits and water quality concerns associated with oxygenates in gasoline, and to provide independent advice and recommendations on ways to maintain air quality while protecting water quality. The Panel, which met six times from January - June 1999, heard presentations in Washington, the Northeast, and California about the benefits and concerns related to RFG and the oxygenates; gathered the best available information on the program and its effects; identified key data gaps; and evaluated a series of alternative recommendations based on their effects on air and water quality and the stability of fuel supply and cost (O'Keefe, 1999). The Panel agreed broadly, but not unanimously, that less MTBE should be used in the RFG program. Among many recommendations, the Panel urged the removal of the legal requirement that RFG contain 2 weight (wt) percent oxygen. Given the Panel recommendations, the EPA Administrator announced that "We must begin to significantly reduce the use of MTBE in gasoline as quickly as possible

without sacrificing the gains we've made in achieving cleaner air" (*Oil & Gas Journal*, 1999).

On November 9, 1998, New Hampshire Governor Jeanne Shaheen requested, on behalf of the New England Governor's Conference, that the Northeast States for Coordinated Air Use Management (NESCAUM) "Review the use and effectiveness of MTBE as a pollution reducing component of reformulated gasoline, consider what effective alternatives may exist that are consistent with statutory options or requirements, and make recommendations regarding the best course for the [Northeast] region to pursue in order to maximize air quality benefits and minimize public health threats." In August 1999, NESCAUM published recommendations for a multi-component strategy that includes legislative and regulatory initiatives to reduce the amount of MTBE in gasoline (NESCAUM, 1999).

On March 25, 1999, California Governor Gray Davis certified that there is significant risk to California's environment associated with continued use of MTBE in gasoline. He directed appropriate state regulatory agencies to devise and carry out a plan to begin immediate phase out of MTBE from California gasoline, with 100 percent removal achieved no later than December 31, 2002.

In Fiscal Year 1996 (FY96), DOE studied pathways for the corn ethanol industry to evolve into a biomass ethanol industry under two predetermined ethanol market share scenarios. Instead of using market assumptions, DOE's follow-up studies in FY97-99 started from "square one," and included a blend demand analysis, a neat demand analysis, and account for competition from gasoline, other alternative fuels, and oxygenates such as MTBE. Refinery modeling was used to estimate the blend demand for ethanol (Hadder, 1998). Given the concerns about the use of MTBE in gasoline, Oak Ridge National Laboratory (ORNL) has used its Refinery Yield Model (ORNL-RYM), in support of the Office of Fuels Development in the DOE OTT, to estimate ethanol demand in the production of gasolines with restricted use of oxygenates.

2. THE ORNL REFINERY YIELD MODEL

ORNL-RYM is an enhanced personal computer version of the Refinery Yield Model of the Refinery Evaluation Modeling System (U.S. DOE, 1984a; U.S. DOE, 1984b; Tallett and Dunbar, 1988; Tallett et al., 1992). The refinery model is a linear program representing 50 refining processes (including new naphtha desulfurization technologies and other updates) 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, Reid vapor pressure (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 incorporates gasoline blending to satisfy formula and emissions standards described by the EPA Complex Model, which predicts pollutant emissions in terms of gasoline properties (Korotney, 1993).

Overoptimization can occur as a result of ORNL-RYM's use of a modeling concept in which refinery hydrocarbon streams with identical distillation cut points are kept separate through different refining processes. Overoptimization of hydrocarbon processing tends to depress the use of ethanol in gasoline blending in the model (Hadder, 1998). 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. However, it has been demonstrated that the use of ratio constraints in regional refinery modeling can over-correct the stream separation problem, leading to overestimation of ethanol used in gasoline blending.

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 costs span a range, and this range has uncertainty. Given variations, uncertainties, and over/underoptimization possibilities, DOE has concluded that both ratio-free and ratio-constrained versions of ORNL-RYM can provide plausible estimates of the range of refining activities. The ratio-free model has been used in this study, for more conservative estimation of ethanol demand.

3. THE ORNL-RYM REPRESENTATION OF CLEANER GASOLINES

3.1 FORMULA AND EMISSIONS STANDARDS

ORNL-RYM represents gasoline blending to satisfy formula and emissions standards mandated by the Clean Air Act Amendments of 1990 (CAAA). The CAAA include programs for oxygenated gasoline and for RFG. The oxygenated gasoline program requires that gasoline with a minimum oxygen content of 2.7 wt percent be sold during winter months in cities not in compliance with carbon monoxide standards. RFG is required in nine areas with extreme or severe ozone pollution problems, and fifteen additional areas have chosen to voluntarily opt-in to the RFG program. The formula and emissions performance standards for RFG produced after 1999 are shown in Table 1 (U.S. EPA, 1994).

Emissions modeling provides a means for predicting the emissions performance of a gasoline, given other properties of the gasoline. The EPA Complex Model is a set of non-linear equations that predicts emissions of volatile organic compounds (VOCs), toxic air pollutants (TAPs), and oxides of nitrogen (NOx) in terms of gasoline properties including RVP, E200, E300, benzene, oxygen, sulfur, aromatics, and olefins contents (Korotney, 1993). The Complex Model has been used since March 1, 1997, to certify the emissions performance of gasolines.

While RFG accounts for about 33 percent of the nation's gasoline market, all gasolines are 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 conventional gasoline (CG) to worsen as polluting fuel components are removed from RFG.

If there is a mandated reduction of MTBE in gasoline, some MTBE could be replaced by high-octane, high toxicity, high-aromatics gasoline blendstocks. With current gasolines emitting less than the statutory limits for toxic air pollutants, it is possible that toxic air pollutants could increase with these high-aromatics replacement blendstocks. This study assumes that new regulations will not allow “toxics-backsliding” (no increase of toxics above recently observed levels). With toxics-backsliding not allowed, low toxicity blendstocks like alkylates are likely to be favored over high-aromatics replacement stocks.

Table 1. Formula and emissions performance standards for the federal RFG program after 1999

Standard	Phase 2 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 meets the specified average emissions performance requirement.

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 NOx 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 objective function value.

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 5 cents per gallon. Third, it is assumed that consumers are indifferent to ethanol blends, neither seeking nor avoiding these gasolines (Anderson et al., 1988).

Technical premises for regional and seasonal product slates and revenues, raw materials and costs, and process capacity data for the ethanol demand study are shown in Tables 2 through 13. These modeling data are based on information sources discussed in the following paragraphs.

4.1 REFINERY PRODUCTS

Refinery net production rates from the *Petroleum Supply Annual 1998* (U.S. DOE, 1999a) are projected by using the Reference Case growth rates published in the *Annual Energy Outlook 1999* (U.S. DOE, 1999b).

Some gasolines are pooled by combining volumes and properties of regular, mid-grade, and premium grades. The source data for octane estimates and for pooling is the *1996 American Petroleum Institute/National Petroleum Refiners Association Survey of Refining Operations and Product Quality* (API/NPRA, 1997) and the *NPRA Survey of U.S. Gasoline Quality and U.S. Refining Industry Capacity to Produce Reformulated Gasolines* (NPRA, 1991).

The production shares of RFG are based on monthly production shares reported in the *Petroleum Supply Annual 1998* (U.S. DOE, 1999a).

Tables 14 and 15 summarize the specifications for gasoline emissions performance standards. To prevent air quality backsliding, RFG is limited to maximum emissions corresponding to the lessor of (1) federal statutory requirements for Phase 2 RFG or (2) emissions calculated from gasoline quality data in the *1996 American Petroleum Institute/National Petroleum Refiners Association Survey of Refining Operations and Product Quality* (API/NPRA, 1997). To prevent air quality backsliding, CG is limited to maximum allowable emissions corresponding to the lessor of (1) Phase 2 RVP volatility control and antidumping or (2) emissions calculated from gasoline quality data in the

Table 2. PADD I+III raw materials and products for year 2006 summer reference conditions

Raw materials

CRUDE/RAW MATERIAL	$/BARREL	MBD
ALGERIAN SAHARAN	24.50	11.2
KUWAIT	20.01	273.1
SAUDI ARABIAN LIGHT	20.73	1701.7
UAE	20.44	1.3
GABON	19.98	239.6
INDONESIA MINAS	20.54	13.8
INDONESIA ATTIKA	23.56	13.8
NIGERIAN MEDIUM	19.38	690.8
VEN BOSCAN	13.12	349.0
VEN BACH	15.52	476.5
VEN TJ MED	18.55	603.9
ANGOLAN	20.27	441.8
ARGENTINA	19.49	81.6
CAMEROON	19.98	1.2
CANADIAN INTERMED	20.16	147.4
CHINA BLEND	19.77	23.1
COLOMBIAN	20.20	290.1
CONGO	19.38	77.4
ECUADOR	19.97	48.3
GUATEMALA	20.85	26.5
EGYPT	15.83	13.2
MALAYSIA	21.69	21.8
MEXICAN ISTHMUS	20.62	716.7
MEXICAN MAYA	16.66	716.7
NORWAY	21.88	239.5
RUSSIA	20.44	9.7
TRINIDAD SWEET	20.85	30.9
TRINIDAD SOUR	18.55	30.9
UK	21.88	156.5
YEMEN	21.92	5.2
OHIO LIGHT	24.93	7.4
ALABAMA LIGHT	23.82	40.4
LOUISIANA COND	28.91	86.7
LOUISIANA NORTH	23.82	50.0
LOUISIANA HVY SWEET	21.49	432.3
MISSISSIPPI HEY	22.95	14.8
MISSISSIPPI BAX	18.78	31.2
NEW MEXICO INT	23.77	18.7
NEW MEXICO SOUR	21.72	38.3
TEXAS CONDENSATE	25.39	53.9
TEXAS GULF REF	23.34	381.1
TEXAS EAST	23.18	60.9
TEXAS HAWKINS	19.84	122.6
TEXAS WEST INTERMED	23.77	344.4
TEXAS WEST SOUR	22.00	82.8
OKLA CEMENT	21.78	27.4
CALIFORNIA ELK HILLS	22.42	53.3
NATURAL GAS (FOE)	17.73	
NATURAL GASOLINE	21.22	<73.3
ISOBUTANE	21.20	<30.6
NORMAL BUTANE	19.02	<17.8
ETHANOL	33.53	
METHANOL	21.41	
MTBE	35.47	
NAPHTHA/REF FEED	24.32	<82.5
GAS OIL HI S	22.00	<116.1

Products

PRODUCT	$/BARREL	MBD
PROCESS GAS C2-FOE	14.88	
STILL GAS TO PETROCHEM	14.88	
ETHANE FOE	14.88	
ETHANE FOE	14.88	
ETHYLENE FOE	14.88	
PROPYLENE TO PETROCHEM	19.25	
PROPANE FUEL(LPG)	15.87	
PROPANE TO PETROCHEM	15.87	
NORMAL BUTANE	18.92	
SURPLUS NC4	18.92	
N BUTYLENE	19.54	
ISO BUTANE	21.10	
ISO BUTYLENE	20.66	
*C2-C4 PRODUCTION SUMS TO 319.4 MBD		
CG POOL (CG-M)	28.71	
CG/ETOH POOL (CG-E)	28.71	
*CG PRODUCTION SUMS TO 3770.2 MBD EQUIVALENT		
RFG REGULAR (RFG-M-R)	28.74	
RFG REMIUM (RFG-M-P)	31.71	
RFG REGULAR/ETOH (RFG-E-R)	28.74	
RFG REMIUM/ETOH (RFG-E-P)	31.71	
*RFG PRODUCTION SUMS TO 1248.2 MBD EQUIVALENT		
AVIATION GAS	32.54	14.7
MIL JET FUEL JP8	25.37	82.5
COMMERCIAL JET A	25.32	1038.7
2D ON-HIGHWAY DIESEL	25.57	1168.6
HEATING OIL (NO2)	23.97	814.9
RESIDUAL <.3S	19.7	
NET RESIDUAL 0.7-1.0 %	17.01	
*RESID PRODUCTION SUMS TO <168.4 MBD		
BUNKER	14.32	
NAPHTHA TO P. CHEM	24.22	
AROMATICS TO P. CHEM	35.35	
(BENZENE = 21 MBD; TOLUENE/XYLENE = 71 MBD)		
GAS OIL TO PETROCHEM	21.90	
*PETROCHEM PRODUCTION SUMS TO 306.8 MBD		
LUBES & WAXES	29.52	148.7
COKE ST/CD LOW SULF	42.08	
COKE ST/CD HIGH SULF	24.36	
COKE ST/CD XTRA HI SULF	5.86	
ROAD OIL & ASPHALT	17.00	<283.0
SULFUR	51.09	

Table 3. PADD I+III process capacity for year 2006 summer Reference conditions

PROCESS	CAPACITY MBSD
CRUDE DISTILLATION	9611.8
VACUUM DISTILLATION	4311.0
FLUID CAT CRACKER	3843.6
FCC MEROX	>0.0
HYDROCRACKER-2 STAGE	617.6
HYDROCRACKER-LOW CONVER	23.0
RESID HYDROCRACKER	213.9
COKER-DELAYED	1117.7
VISBREAKER	35.5
SOLVENT DEASPHALTING	252.8
LUBE + WAX PLANTS	176.8
NAPHTHA HYDROTREATER	2514.0
DISTILLATE HDS	2420.1
MID DIST DEEP HT	401.8
FCC FEED HYDROFINER	976.2
ATM RESID DESULF	290.9
HP SEMI REGEN REFORMER	717.2
LP CYCLIC REFORMER	628.9
LP CONTINUOUS REFORMER	885.0
ALKYLATION PLANT	735.3
CAT POLYMERIZATION	54.3
DIMERSOL	4.0
BUTANE ISOMERIZATION	98.8
PEN/HEX ISOMERIZATION	464.2
AROMATICS RECOVERY(BTX)	256.5
MTBE(ETHEROL)	113.4
OCTGAIN	0.0
GASOLINE SYNSAT	0.0
CDTECH/FCC NAPHTHA DESUL	1112.2
ALKY OF BENZENE	0.0
REFORMATE SPLITTER	839.5
NAPHTHA SPLITTER	867.5
FCC GASOLINE SPLR	855.5
HYDROGEN PLT,MBPD FOE	80.0
SULFUR PLANT,MST/D	18.8

Table 4. PADD I+III raw materials and products for year 2006 summer with 3 percent maximum MTBE

Raw materials

CRUDE/RAW MATERIAL	$/BARREL	MBD
ALGERIAN SAHARAN	24.50	11.3
KUWAIT	20.01	276.0
SAUDI ARABIAN LIGHT	20.73	1719.5
UAE	20.44	1.3
GABON	19.98	242.2
INDONESIA MINAS	20.54	13.9
INDONESIA ATTIKA	23.56	13.9
NIGERIAN MEDIUM	19.38	698.0
VEN BOSCAN	13.12	352.7
VEN BACH	15.52	481.4
VEN TJ MED	18.55	610.2
ANGOLAN	20.27	446.5
ARGENTINA	19.49	82.5
CAMEROON	19.98	1.2
CANADIAN INTERMED	20.16	148.9
CHINA BLEND	19.77	23.3
COLOMBIAN	20.20	293.2
CONGO	19.38	78.2
ECUADOR	19.97	48.8
GUATEMALA	20.85	26.8
EGYPT	15.83	13.3
MALAYSIA	21.69	22.0
MEXICAN ISTHMUS	20.62	724.2
MEXICAN MAYA	16.66	724.2
NORWAY	21.88	242.0
RUSSIA	20.44	9.8
TRINIDAD SWEET	20.85	31.3
TRINIDAD SOUR	18.55	31.3
UK	21.88	158.2
YEMEN	21.92	5.2
OHIO LIGHT	24.93	7.5
ALABAMA LIGHT	23.82	40.8
LOUISIANA COND	28.91	87.6
LOUISIANA NORTH	23.82	50.5
LOUISIANA HVY SWEET	21.49	436.8
MISSISSIPPI HEY	22.95	15.0
MISSISSIPPI BAX	18.78	31.6
NEW MEXICO INT	23.77	18.9
NEW MEXICO SOUR	21.72	38.7
TEXAS CONDENSATE	25.39	54.4
TEXAS GULF REF	23.34	385.1
TEXAS EAST	23.18	61.5
TEXAS HAWKINS	19.84	123.9
TEXAS WEST INTERMED	23.77	348.0
TEXAS WEST SOUR	22.00	83.6
OKLAHOMA CEMENT	21.78	27.7
CALIFORNIA ELK HILLS	22.42	53.8
NATURAL GAS (FOE)	17.73	
NATURAL GASOLINE	21.22	<73.3
ISOBUTANE	21.20	<30.6
NORMAL BUTANE	19.02	<17.8
ETHANOL	33.53	
METHANOL	21.41	
MTBE	35.47	
NAPHTHA/REF FEED	24.32	<82.5
GAS OIL HI S	22.00	<116.1

Products

PRODUCT	$/BARREL	MBD
PROCESS GAS C2-FOE	14.88	
STILL GAS TO PETROCHEM	14.88	
ETHANE FOE	14.88	
ETHANE FOE	14.88	
ETHYLENE FOE	14.88	
PROPYLENE TO PETROCHEM	19.25	
PROPANE FUEL(LPG)	15.87	
PROPANE TO PETROCHEM	15.87	
NORMAL BUTANE	18.92	
SURPLUS NC4	18.92	
N BUTYLENE	19.54	
ISO BUTANE	21.10	
ISO BUTYLENE	20.66	
*C2-C4 PRODUCTION SUMS TO 319.4 MBD		
CG POOL (CG-M)	28.71	
CG/ETOH POOL (CG-E)	28.71	
*CG PRODUCTION SUMS TO 3770.2 MBD EQUIVALENT		
RFG REGULAR (RFG-M-R)	28.74	
RFG REMIUM (RFG-M-P)	31.71	
RFG REGULAR/ETOH (RFG-E-R)	28.74	
RFG REMIUM/ETOH (RFG-E-P)	31.71	
*RFG PRODUCTION SUMS TO 1248.2 MBD EQUIVALENT		
AVIATION GAS	32.54	14.7
MIL JET FUEL JP8	25.37	82.5
COMMERCIAL JET A	25.32	1038.7
2D ON-HIGHWAY DIESEL	25.57	1168.6
HEATING OIL (NO2)	23.97	814.9
RESIDUAL <.3S	19.7	
NET RESIDUAL 0.7-1.0 %	17.01	
*RESID PRODUCTION SUMS TO <168.4 MBD		
BUNKER	14.32	
NAPHTHA TO P. CHEM	24.22	
AROMATICS TO P. CHEM	35.35	
(BENZENE = 21 MBD; TOLUENE/XYLENE = 71 MBD)		
GAS OIL TO PETROCHEM	21.90	
*PETROCHEM PRODUCTION SUMS TO 306.8 MBD		
LUBES & WAXES	29.52	148.7
COKE ST/CD LOW SULF	42.08	
COKE ST/CD HIGH SULF	24.36	
COKE ST/CD XTRA HI SULF	5.86	
ROAD OIL & ASPHALT	17.00	<283.0
SULFUR	51.09	

Table 5. PADD I+III process capacity for year 2006 summer with 3 percent maximum MTBE

PROCESS	CAPACITY MBSD
CRUDE DISTILLATION	9611.8
VACUUM DISTILLATION	4311.0
FLUID CAT CRACKER	3843.6
FCC MEROX	>0.0
HYDROCRACKER-2 STAGE	617.6
HYDROCRACKER-LOW CONVER	23.0
RESID HYDROCRACKER	213.9
COKER-DELAYED	1117.7
VISBREAKER	35.5
SOLVENT DEASPHALTING	252.8
LUBE + WAX PLANTS	176.8
NAPHTHA HYDROTREATER	2514.0
DISTILLATE HDS	2420.1
MID DIST DEEP HT	401.8
FCC FEED HYDROFINER	976.2
ATM RESID DESULF	290.9
HP SEMI REGEN REFORMER	717.2
LP CYCLIC REFORMER	628.9
LP CONTINUOUS REFORMER	885.0
ALKYLATION PLANT	735.3
CAT POLYMERIZATION	54.3
DIMERSOL	4.0
BUTANE ISOMERIZATION	98.8
PEN/HEX ISOMERIZATION	470.7
AROMATICS RECOVERY(BTX)	256.5
MTBE(ETHEROL)	113.4
OCTGAIN	0.0
GASOLINE SYNSAT	0.0
CDTECH/FCC NAPHTHA DESUL	1112.2
ALKY OF BENZENE	0.0
REFORMATE SPLITTER	839.5
NAPHTHA SPLITTER	867.5
FCC GASOLINE SPLR	855.5
HYDROGEN PLT,MBPD FOE	80.0
SULFUR PLANT,MST/D	18.8

Table 6. PADD I+III raw materials and products for year 2006 winter with 3 percent maximum MTBE

Raw materials

CRUDE/RAW MATERIAL	$/BARREL	MBD
ALGERIAN SAHARAN	24.82	11.4
KUWAIT	20.22	264.6
SAUDI ARABIAN LIGHT	20.95	1648.6
UAE	20.66	1.2
GABON	20.18	232.2
INDONESIA MINAS	20.75	13.3
INDONESIA ATTIKA	23.86	13.3
NIGERIAN MEDIUM	19.56	669.2
VEN BOSCAN	13.14	338.2
VEN BACH	15.60	461.5
VEN TJ MED	18.71	585.0
ANGOLAN	20.48	428.1
ARGENTINA	19.68	79.1
CAMEROON	20.18	1.2
CANADIAN INTERMED	20.37	142.8
CHINA BLEND	19.96	22.3
COLOMBIAN	20.41	281.1
CONGO	19.56	75.0
ECUADOR	20.17	46.8
GUATEMALA	21.07	25.7
EGYPT	15.92	12.8
MALAYSIA	21.94	21.1
MEXICAN ISTHMUS	20.84	694.3
MEXICAN MAYA	16.77	694.3
NORWAY	22.13	232.0
RUSSIA	20.65	9.4
TRINIDAD SWEET	21.07	30.0
TRINIDAD SOUR	18.71	30.0
UK	22.13	151.7
YEMEN	22.17	5.0
OHIO LIGHT	25.32	7.2
ALABAMA LIGHT	24.21	39.1
LOUISIANA COND	29.30	84.0
LOUISIANA NORTH	24.21	48.4
LOUISIANA HVY SWEET	21.88	418.8
MISSISSIPPI HEY	23.34	14.4
MISSISSIPPI BAX	19.16	30.3
NEW MEXICO INT	24.15	18.1
NEW MEXICO SOUR	22.10	37.1
TEXAS CONDENSATE	25.78	52.2
TEXAS GULF REF	23.73	369.2
TEXAS EAST	23.56	59.0
TEXAS HAWKINS	20.23	118.8
TEXAS WEST INTERMED	24.15	333.6
TEXAS WEST SOUR	22.38	80.2
OKLAHOMA CEMENT	22.17	26.6
CALIFORNIA ELK HILLS	22.80	51.6
NATURAL GAS (FOE)	17.93	
NATURAL GASOLINE	19.47	<70.8
ISOBUTANE	22.77	<30.6
NORMAL BUTANE	20.43	<95.6
ETHANOL	47.24	
METHANOL	19.66	
MTBE	33.72	
NAPHTHA/REF FEED	22.57	<82.5
GAS OIL HI S	22.97	<116.1

Products

PRODUCT	$/BARREL	MBD
PROCESS GAS C2-FOE	15.99	
STILL GAS TO PETROCHEM	15.99	
ETHANE FOE	15.99	
ETHANE FOE	15.99	
ETHYLENE FOE	15.99	
PROPYLENE TO PETROCHEM	20.68	
PROPANE FUEL(LPG)	17.05	
PROPANE TO PETROCHEM	17.05	
NORMAL BUTANE	20.33	
SURPLUS NC4	20.33	
N BUTYLENE	20.99	
ISO BUTANE	22.67	
ISO BUTYLENE	22.20	
CG POOL (CG-M)	26.96	
CG/ETOH POOL (CG-E)	26.96	
*CG PRODUCTION SUMS TO 3535.2 MBD EQUIVALENT		
RFG REGULAR (RFG-M-R)	27.60	
RFG REMIUM (RFG-M-P)	32.03	
RFG REGULAR/ETOH (RFG-E-R)	27.60	
RFG REMIUM/ETOH (RFG-E-P)	32.03	
*RFG PRODUCTION SUMS TO 1313.7 MBD EQUIVALENT		
AVIATION GAS	32.86	13.6
MIL JET FUEL JP8	24.85	80.4
COMMERCIAL JET A	24.80	1083.3
2D ON-HIGHWAY DIESEL	25.04	1169.4
HEATING OIL (NO2)	24.94	815.2
RESIDUAL <.3S	19.65	
NET RESIDUAL 0.7-1.0 %	16.96	
BUNKER	14.90	
NAPHTHA TO P. CHEM	22.47	
AROMATICS TO P. CHEM	33.60	
(BENZENE < 41.9 MBD; TOLUENE/XYLENE = 71 TO 129.5 MBD)		
GAS OIL TO PETROCHEM	22.87	
*PETROCHEM PRODUCTION SUMS TO 300.8 MBD		
LUBES & WAXES	29.85	149.0
COKE ST/CD LOW SULF	42.54	
COKE ST/CD HIGH SULF	24.63	
COKE ST/CD XTRA HI SULF	5.92	
ROAD OIL & ASPHALT	17.19	<191.1
SULFUR	53.67	

Table 7. PADD I+III process capacity for year 2006 winter with 3 percent maximum MTBE (with summer investment capacity added)

PROCESS	CAPACITY MBSD
CRUDE DISTILLATION	9687.1
VACUUM DISTILLATION	4311.0
FLUID CAT CRACKER	4049.0
FCC MEROX	>0.0
HYDROCRACKER-2 STAGE	617.6
HYDROCRACKER-LOW CONVER	23.0
RESID HYDROCRACKER	249.5
COKER-DELAYED	1117.7
VISBREAKER	35.5
SOLVENT DEASPHALTING	252.8
LUBE + WAX PLANTS	176.8
NAPHTHA HYDROTREATER	2571.3
DISTILLATE HDS	2420.1
MID DIST DEEP HT	401.8
FCC FEED HYDROFINER	976.2
ATM RESID DESULF	290.9
HP SEMI REGEN REFORMER	717.2
LP CYCLIC REFORMER	628.9
LP CONTINUOUS REFORMER	959.8
ALKYLATION PLANT	764.8
CAT POLYMERIZATION	54.4
DIMERSOL	4.0
BUTANE ISOMERIZATION	98.8
PEN/HEX ISOMERIZATION	499.9
AROMATICS RECOVERY(BTX)	256.5
MTBE(ETHEROL)	113.4
OCTGAIN	0.0
GASOLINE SYNSAT	0.0
CDTECH/FCC NAPHTHA DESUL	1183.0
ALKY OF BENZENE	0.0
REFORMATE SPLITTER	839.5
NAPHTHA SPLITTER	867.5
FCC GASOLINE SPLR	855.5
HYDROGEN PLT,MBPD FOE	80.0
SULFUR PLANT,MST/D	19.3

Table 8. PADD II raw materials and products for year 2006 summer Reference conditions

Raw materials

CRUDE/RAW MATERIAL	$/BARREL	MBD
KUWAIT	20.01	35.1
SAUDI ARABIAN HEAVY	18.88	3.8
SAUDI ARABIAN MEDIUM	19.79	1.9
SAUDI ARABIAN LIGHT	20.73	206.2
SAUDI BERRI	22.66	15.0
IRAQ	20.86	37.1
UAE	20.44	1.7
GABON	19.98	1.1
INDONESIA MINAS	20.54	3.0
INDONESIA ATTIKA	23.56	2.8
NIGERIAN FORCADOS	20.45	22.2
NIGERIAN MEDIUM	19.38	79.5
NIGERIAN LIGHT	23.97	15.4
VEN BOSCAN	13.12	87.4
VEN BACH	15.52	74.9
VEN TJ MED	18.55	0.4
ANGOLAN	20.27	104.9
ARGENTINA	19.49	0.8
CANADIAN HVY	17.10	381.3
CANADIAN LLOYD	18.72	373.7
CANADIAN INTERPR	20.72	150.0
CANADIAN FED	23.19	78.8
CANADIAN RANGLD	23.12	142.4
COLOMBIAN	20.20	123.9
CONGO	19.38	5.0
ECUADOR	19.97	2.5
MALAYSIA	21.69	0.4
MEXICAN ISTHMUS	20.62	35.4
MEXICAN MAYA	16.66	45.0
NORWAY	21.88	19.3
UK	21.88	31.0
ALABAMA HEAVY	19.97	7.0
ALASKA NORTH SLOPE	19.72	3.9
LOUISIANA LIGHT	22.63	139.3
LOUISIANA HVY SWEET	21.49	111.4
MISSISSIPPI HEY	22.95	40.1
ILLINOIS SWEET	24.03	29.3
INDIANA SWEET	23.34	4.7
KANSAS SWEET	24.25	79.5
KENTUCKY SWEET	23.34	8.9
MICHIGAN SWEET	24.03	30.9
OKLAHOMA CEMET	21.78	56.2
OKLAHOMA COND	26.00	6.3
OKLAHOMA GARBER	24.25	65.9
SOUTH DAKOTA SWEET	22.92	3.1
NEW MEXICO INTER	23.77	158.8
COLORADO RANGLEY	22.84	1.1
MONTANA SOUR	19.29	0.2
WYOMING SOUR	19.29	16.5
WYOMING SWEET	22.92	14.7
TEXAS EAST	23.18	139.3
TEXAS SCURRY	23.60	52.9
TEXAS WEST INTERMEDIATE	23.77	172.7
TEXAS SOUR	22.00	463.9

Products

PRODUCT	$/BARREL	MBD
PROCESS GAS C2-FOE	15.54	
STILL GAS TO PETROCHEM	15.54	
ETHANE FOE	15.54	
ETHANE FOE	15.54	
ETHYLENE FOE	15.54	
PROPYLENE TO PETROCHEM	20.10	
PROPANE FUEL(LPG)	16.57	
PROPANE TO PETROCHEM	16.57	
NORMAL BUTANE	19.75	
SURPLUS NC4	19.75	
N BUTYLENE	20.40	
ISO BUTANE	22.03	
ISO BUTYLENE	21.57	
CG POOL (CG-M)	29.77	
CG/ETOH POOL (CG-E)	29.77	
*CG PRODUCTION SUMS TO 1697.0 MBD EQUIVALENT		
RFG REGULAR (RFG-M-R)	29.80	
RFG REMIUM (RFG-M-P)	32.77	
RFG REGULAR/ETOH (RFG-E-R)	29.80	
RFG REMIUM/ETOH (RFG-E-P)	32.77	
*RFG PRODUCTION SUMS TO 352.9 MBD EQUIVALENT		
AVIATION GAS	33.60	4.9
MIL JET FUEL JP8	26.48	14.0
COMMERCIAL JET A	26.43	262.2
2D ON-HIGHWAY DIESEL	26.63	657.3
HEATING OIL (NO2)	25.03	262.9
RESIDUAL <.3S	20.45	
NET RESIDUAL 0.7-1.0 %	17.76	
*RESID PRODUCTION SUMS TO <68.2 MBD		
BUNKER	15.07	
NAPHTHA TO P. CHEM	25.28	
AROMATICS TO P. CHEM	36.41	
(BENZENE <2.3 MBD; TOLUENE/XYLENE <15.8 MBD)		
GAS OIL TO PETROCHEM	22.96	
*PETROCHEM PRODUCTION SUMS TO <68.1 MBD		
LUBES & WAXES	30.82	28.6
COKE ST/CD LOW SULF	43.94	
COKE ST/CD HIGH SULF	25.43	
COKE ST/CD XTRA HI SULF	6.12	
ROAD OIL & ASPHALT	17.75	<215.9
SULFUR	53.34	

Table 8 (Continued). PADD II raw materials and products for year 2006 summer Reference conditions

Raw materials			Products		
CRUDE/RAW MATERIAL	$/BARREL	MBD	PRODUCT	$/BARREL	MBD
NATURAL GAS (FOE)	18.51				
NATURAL GASOLINE	22.28	<39.3			
ISOBUTANE	22.13	<46.1			
NORMAL BUTANE	19.85	<32.2			
ETHANOL	30.10				
METHANOL	22.49				
MTBE	36.53				
NAPHTHA/REF FEED	25.38	<27.2			
GAS OIL MED S	23.06	<29.8			
GASOLINE BLEND STOCKS	37.72	<17.6			

Table 9. PADD II process capacity for year 2006 summer Reference conditions

PROCESS	CAPACITY MBSD
CRUDE DISTILLATION	4008.5
VACUUM DISTILLATION	1491.4
FLUID CAT CRACKER	1555.9
MEROX	>0.0
HYDROCRACKER-2 STAGE	325.4
HYDROCRACKER-LOW CONVER	12.5
COKER-DELAYED	421.2
SOLVENT DEASPHALTING	37.4
LUBE + WAX PLANTS	34.5
NAPHTHA HYDROTREATER	1319.0
DISTILLATE HDS	764.6
MID DIST DEEP HT	326.0
FCC FEED HYDROFINER	540.0
ATM RESID DESULF	66.8
HP SEMI REGEN REFORMER	279.3
LP CYCLIC REFORMER	155.3
LP CONTINUOUS REFORMER	629.8
ALKYLATION PLANT	351.5
CAT POLYMERIZATION	13.6
DIMERSOL	5.2
BUTANE ISOMERIZATION	22.7
PEN/HEX ISOMERIZATION	258.5
AROMATICS RECOVERY(BTX)	51.2
MTBE(ETHEROL)	13.8
OCTGAIN	0.0
GASOLINE SYNSAT	0.0
CDTECH/FCC NAPHTHA DESUL	442.8
ALKY OF BENZENE	0.0
REFORMATE SPLITTER	297.9
NAPHTHA SPLITTER	173.0
FCC GASOLINE SPLR	175.3
HYDROGEN PLT,MBPD FOE	23.2
SULFUR PLANT,MST/D	6.6

Table 10. PADD II raw materials and products for year 2006 summer MTBE ban

Raw materials

CRUDE/RAW MATERIAL	$/BARREL	MBD
KUWAIT	20.01	35.2
SAUDI ARABIAN HEAVY	18.88	3.8
SAUDI ARABIAN MEDIUM	19.79	1.9
SAUDI ARABIAN LIGHT	20.73	206.7
SAUDI BERRI	22.66	15.0
IRAQ	20.86	37.2
UAE	20.44	1.7
GABON	19.98	1.1
INDONESIA MINAS	20.54	3.0
INDONESIA ATTIKA	23.56	2.8
NIGERIAN FORCADOS	20.45	22.3
NIGERIAN MEDIUM	19.38	79.7
NIGERIAN LIGHT	23.97	15.4
VEN BOSCAN	13.12	87.6
VEN BACH	15.52	75.1
VEN TJ MED	18.55	0.4
ANGOLAN	20.27	105.1
ARGENTINA	19.49	0.8
CANADIAN HVY	17.10	382.3
CANADIAN LLOYD	18.72	374.6
CANADIAN INTERPR	20.72	150.4
CANADIAN FED	23.19	79.0
CANADIAN RANGLD	23.12	142.7
COLOMBIAN	20.20	124.2
CONGO	19.38	5.0
ECUADOR	19.97	2.5
MALAYSIA	21.69	0.4
MEXICAN ISTHMUS	20.62	35.5
MEXICAN MAYA	16.66	45.1
NORWAY	21.88	19.3
UK	21.88	31.1
ALABAMA HEAVY	19.97	7.0
ALASKA NORTH SLOPE	19.72	3.9
LOUISIANA LIGHT	22.63	139.6
LOUISIANA HVY SWEET	21.49	111.7
MISSISSIPPI HEY	22.95	40.2
ILLINOIS SWEET	24.03	29.4
INDIANA SWEET	23.34	4.7
KANSAS SWEET	24.25	79.7
KENTUCKY SWEET	23.34	8.9
MICHIGAN SWEET	24.03	30.9
OKLAHOMA CEMET	21.78	56.4
OKLAHOMA COND	26.00	6.3
OKLAHOMA GARBER	24.25	66.1
SOUTH DAKOTA SWEET	22.92	3.1
NEW MEXICO INTER	23.77	159.2
COLORADO RANGLEY	22.84	1.2
MONTANA SOUR	19.29	0.2
WYOMING SOUR	19.29	16.5
WYOMING SWEET	22.92	14.7
TEXAS EAST	23.18	139.6
TEXAS SCURRY	23.60	53.1
TEXAS WEST INTERMEDIATE	23.77	173.2
TEXAS SOUR	22.00	465.0

Products

PRODUCT	$/BARREL	MBD
PROCESS GAS C2-FOE	15.54	
STILL GAS TO PETROCHEM	15.54	
ETHANE FOE	15.54	
ETHANE FOE	15.54	
ETHYLENE FOE	15.54	
PROPYLENE TO PETROCHEM	20.10	
PROPANE FUEL(LPG)	16.57	
PROPANE TO PETROCHEM	16.57	
NORMAL BUTANE	19.75	
SURPLUS NC4	19.75	
N BUTYLENE	20.40	
ISO BUTANE	22.03	
ISO BUTYLENE	21.57	
CG POOL (CG-M)	29.77	
CG/ETOH POOL (CG-E)	29.77	
*CG PRODUCTION SUMS TO 1697.0 MBD EQUIVALENT		
RFG REGULAR (RFG-M-R)	29.80	
RFG REMIUM (RFG-M-P)	32.77	
RFG REGULAR/ETOH (RFG-E-R)	29.80	
RFG REMIUM/ETOH (RFG-E-P)	32.77	
*RFG PRODUCTION SUMS TO 352.9 MBD EQUIVALENT		
AVIATION GAS	33.60	4.9
MIL JET FUEL JP8	26.48	14.0
COMMERCIAL JET A	26.43	262.2
2D ON-HIGHWAY DIESEL	26.63	657.3
HEATING OIL (NO2)	25.03	262.9
RESIDUAL <.3S	20.45	
NET RESIDUAL 0.7-1.0 %	17.76	
*RESID PRODUCTION SUMS TO <68.2 MBD		
BUNKER	15.07	
NAPHTHA TO P. CHEM	25.28	
AROMATICS TO P. CHEM	36.41	
(BENZENE <2.3 MBD; TOLUENE/XYLENE <15.8 MBD)		
GAS OIL TO PETROCHEM	22.96	
*PETROCHEM PRODUCTION SUMS TO <68.1 MBD		
LUBES & WAXES	30.82	28.6
COKE ST/CD LOW SULF	43.94	
COKE ST/CD HIGH SULF	25.43	
COKE ST/CD XTRA HI SULF	6.12	
ROAD OIL & ASPHALT	17.75	<215.9
SULFUR	53.34	

Table 10 (Continued). PADD II raw materials and products for year 2006 summer MTBE ban

Raw materials			Products		
CRUDE/RAW MATERIAL	$/BARREL	MBD	PRODUCT	$/BARREL	MBD
NATURAL GAS (FOE)	18.51				
NATURAL GASOLINE	22.28	<39.3			
ISOBUTANE	22.13	<46.1			
NORMAL BUTANE	19.85	<32.2			
ETHANOL	33.99				
NAPHTHA/REF FEED	25.38	<27.2			
GAS OIL MED S	23.06	<29.8			
GASOLINE BLEND STOCKS	37.72	<17.6			

Table 11. PADD II process capacity for year 2006 summer MTBE ban

PROCESS	CAPACITY MBSD
CRUDE DISTILLATION	4008.5
VACUUM DISTILLATION	1491.4
FLUID CAT CRACKER	1555.9
MEROX	>0.0
HYDROCRACKER-2 STAGE	325.4
HYDROCRACKER-LOW CONVER	12.5
COKER-DELAYED	427.6
SOLVENT DEASPHALTING	37.4
LUBE + WAX PLANTS	34.5
NAPHTHA HYDROTREATER	1319.0
DISTILLATE HDS	764.6
MID DIST DEEP HT	326.0
FCC FEED HYDROFINER	540.0
ATM RESID DESULF	66.8
HP SEMI REGEN REFORMER	279.3
LP CYCLIC REFORMER	155.3
LP CONTINUOUS REFORMER	629.8
ALKYLATION PLANT	351.5
CAT POLYMERIZATION	13.6
DIMERSOL	5.2
BUTANE ISOMERIZATION	22.7
PEN/HEX ISOMERIZATION	258.5
AROMATICS RECOVERY(BTX)	51.2
MTBE(ETHEROL)	13.8
OCTGAIN	0.0
GASOLINE SYNSAT	0.0
CDTECH/FCC NAPHTHA DESUL	442.8
ALKY OF BENZENE	0.0
REFORMATE SPLITTER	297.9
NAPHTHA SPLITTER	173.0
FCC GASOLINE SPLR	284.6
HYDROGEN PLT,MBPD FOE	27.8
SULFUR PLANT,MST/D	6.6

Table 12. PADD II raw materials and products for year 2006 winter MTBE ban

Raw materials[a]

CRUDE/RAW MATERIAL	$/BARREL	MBD
ALGERIAN SAHARAN	24.50	4.4
KUWAIT	20.01	106.4
SAUDI ARABIAN LIGHT	20.73	662.8
UAE	20.44	0.5
GABON	19.98	93.3
INDONESIA MINAS	20.54	5.4
INDONESIA ATTIKA	23.56	5.4
NIGERIAN MEDIUM	19.38	269.0
VEN BOSCAN	13.12	135.9
VEN BACH	15.52	185.6
VEN TJ MED	18.55	235.2
ANGOLAN	20.27	172.1
ARGENTINA	19.49	31.8
CAMEROON	19.98	0.5
CANADIAN INTERMED	20.16	57.4
CHINA BLEND	19.77	9.0
COLOMBIAN	20.20	113.0
CONGO	19.38	30.1
ECUADOR	19.97	18.8
GUATEMALA	20.85	10.3
EGYPT	15.83	5.1
MALAYSIA	21.69	8.5
MEXICAN ISTHMUS	20.62	279.1
MEXICAN MAYA	16.66	279.1
NORWAY	21.88	93.3
RUSSIA	20.44	3.8
TRINIDAD SWEET	20.85	12.0
TRINIDAD SOUR	18.55	12.0
UK	21.88	61.0
YEMEN	21.92	2.0
OHIO LIGHT	24.93	2.9
ALABAMA LIGHT	23.82	15.7
LOUISIANA COND	28.91	33.8
LOUISIANA NORTH	23.82	19.5
LOUISIANA HVY SWEET	21.49	168.4
MISSISSIPPI HEY	22.95	5.8
MISSISSIPPI BAX	18.78	12.2
NEW MEXICO INT	23.77	7.3
NEW MEXICO SOUR	21.72	14.9
TEXAS CONDENSATE	25.39	21.0
TEXAS GULF REF	23.34	148.4
TEXAS EAST	23.18	61.5
TEXAS HAWKINS	19.84	123.9
TEXAS WEST INTERMED	23.77	134.1
TEXAS WEST SOUR	22.00	32.2
OKLAHOMA CEMENT	21.78	10.7
CALIFORNIA ELK HILLS	22.42	20.8
NATURAL GAS (FOE)	18.74	
NATURAL GASOLINE	19.66	<43.5
ISOBUTANE	22.41	<50.1
NORMAL BUTANE	20.10	
ETHANOL	29.92	
NAPHTHA/REF FEED	22.79	<36.8
GAS OIL MED S	23.37	<30.1

Products

PRODUCT	$/BARREL	MBD
PROCESS GAS C2-FOE	15.73	
STILL GAS TO PETROCHEM	15.73	
ETHANE FOE	15.73	
ETHANE FOE	15.73	
ETHYLENE FOE	15.73	
PROPYLENE TO PETROCHEM	20.35	
PROPANE FUEL(LPG)	16.78	
PROPANE TO PETROCHEM	16.78	
NORMAL BUTANE	20.00	
SURPLUS NC4	20.00	
N BUTYLENE	20.65	
ISO BUTANE	22.30	
ISO BUTYLENE	21.84	
CG POOL (CG-M)	27.18	
CG/ETOH POOL (CG-E)	27.18	
*CG PRODUCTION SUMS TO 1753.0 MBD EQUIVALENT		
RFG REGULAR (RFG-M-R)	28.07	
RFG REMIUM (RFG-M-P)	29.75	
RFG REGULAR/ETOH (RFG-E-R)	28.07	
RFG REMIUM/ETOH (RFG-E-P)	29.75	
*RFG PRODUCTION SUMS TO 330.5 MBD EQUIVALENT		
AVIATION GAS	33.91	4.7
MIL JET FUEL JP8	26.79	13.7
COMMERCIAL JET A	26.74	283.9
2D ON-HIGHWAY DIESEL	26.94	637.4
HEATING OIL (NO2)	25.34	255.0
RESIDUAL <.3S	20.71	
NET RESIDUAL 0.7-1.0 %	17.98	
BUNKER	15.26	
NAPHTHA TO P. CHEM	22.69	
AROMATICS TO P. CHEM	33.82	
(BENZENE <2.3 MBD; TOLUENE/XYLENE <15.8 MBD)		
GAS OIL TO PETROCHEM	23.27	
*PETROCHEM PRODUCTION SUMS TO <48.4 MBD		
LUBES & WAXES	31.20	28.0
COKE ST/CD LOW SULF	44.49	
COKE ST/CD HIGH SULF	25.75	
COKE ST/CD XTRA HI SULF	6.20	
ROAD OIL & ASPHALT	17.97	<167.8
SULFUR	54.01	

[a]Crude misspecification does not materially affect results; sulfur difference is well within variability of source data.

Table 13. PADD II process capacity for year 2006 winter MTBE ban

PROCESS	CAPACITY MBSD
CRUDE DISTILLATION	4008.5
VACUUM DISTILLATION	1491.4
FLUID CAT CRACKER	1555.9
MEROX	>0.0
HYDROCRACKER-2 STAGE	325.4
HYDROCRACKER-LOW CONVER	12.5
COKER-DELAYED	427.6
SOLVENT DEASPHALTING	37.4
LUBE + WAX PLANTS	34.5
NAPHTHA HYDROTREATER	1319.0
DISTILLATE HDS	764.6
MID DIST DEEP HT	326.0
FCC FEED HYDROFINER	540.0
ATM RESID DESULF	66.8
HP SEMI REGEN REFORMER	279.3
LP CYCLIC REFORMER	155.3
LP CONTINUOUS REFORMER	629.8
ALKYLATION PLANT	351.5
CAT POLYMERIZATION	13.6
DIMERSOL	5.2
BUTANE ISOMERIZATION	22.7
PEN/HEX ISOMERIZATION	258.5
AROMATICS RECOVERY(BTX)	51.2
MTBE(ETHEROL)	13.8
OCTGAIN	0.0
GASOLINE SYNSAT	0.0
CDTECH/FCC NAPHTHA DESUL	464.1
ALKY OF BENZENE	0.0
REFORMATE SPLITTER	297.9
NAPHTHA SPLITTER	173.0
FCC GASOLINE SPLR	284.6
HYDROGEN PLT,MBPD FOE	27.8
SULFUR PLANT,MST/D	6.6

Table 14. PADD I+ III specifications for emissions performance standards for year 2006

Summer	Winter
*PHASE II "REGULATORY" ("REG") STANDARDS: *CG STANDARD ASSUMES QUALITY REPORTED IN THE API/NPRA SURVEY (API/NPRA,1997) *SO "REGULATORY" FOR CG IN COMBINED PADDS: * *TAP<88.0; NOX<1372.3; VOC<1605.0. * *BASELINES FOR EPA-DEFINED REGIONS ARE: * REGION B C * VOC 1466.31 1399.07 * TAP 86.3443 85.6077 * NOX 1340 1340 *NOX REDUCTION IS 6.8 PERCENT: 1248.88 MG/MI * *VOC REDUCTION 29% B; 27.4% C; *SO "REGULATORY" VOC = .39*(1041.1)+.61(1015.7) = 1025.6 AVERAGING * *TAP REDUCTION IS 21.5% YEAR ROUND. *ASSUME 25% SUMMER REDUCTION WILL SATISFY YEAR ROUND *SO "REGULATORY TAP" = .39(64.76)+.61(64.21) = 64.7 * *PREMISE FOR NO BACKSLIDING OVERRIDES SOME REGULATORY LIMITS *BASED ON API/NPRA SURVEY GASOLINE QUALITIES: * *CG REG (TAP=79.05; NOX=1372.3"REG"; VOC=1311.6) *CG PREM (TAP=71.53; NOX=1230.9; VOC=1314.2) *CG POOL (TAP=77.28; NOX=1339.1; VOC=1312.2) *CG/ETOH POOL ("ESTIMATED" TAP=72.4; NOX=1353.68; VOC=1472.7) *RFG REG (TAP=61.74; NOX=1248.9"REG"; VOC=1025.6"REG") *RFG PREM (TAP=61.54; NOX=1248.9"REG"; VOC=1025.6"REG")	*ABSENT BACKSLIDING DATA, USE BASELINE FACTORS: WINTER/SUMMER = 1540/1340 FOR NOX; 127.24/86.64 FOR TAP. *WINTER CG POOL (TAP=113.5; NOX=1540) *WINTER CG/ETOH POOL ("ESTIMATED" TAP=106.3; NOX=1555.7) *WINTER RFG REG (TAP=90.67; NOX=1516.9, A 1.5% REDUCTION) *WINTER RFG PREM (TAP=90.37; NOX=1516.9, A 1.5% REDUCTION)

Table 15. PADD II specifications for emissions performance standards for year 2006	
Summer	Winter
*PHASE II "REGULATORY" ("REG") STANDARDS: *CG STANDARD ASSUMES QUALITY REPORTED IN THE API/NPRA SURVEY (API/NPRA,1997) *SO "REGULATORY" WITHOUT BACKSLIDING IN PADD 2: * *TAP<80.1; NOX<1343.7; VOC<1350.9. * *BASELINES FOR EPA-DEFINED REGIONS ARE: * REGION B C * VOC 1466.31 1399.07 * TAP 86.3443 85.6077 * NOX 1340 1340 *NOX REDUCTION IS 6.8 PERCENT: 1248.88 MG/MI * *VOC REDUCTION 29% B; 27.4% C; *SO "REGULATORY" VOC = .2*(1041.1)+.8*(1015.7) = 1020.8 AVERAGING *WHERE NPC CLASS SHARES ARE USED * *TAP REDUCTION IS 21.5% YEAR ROUND. *ASSUME 25% SUMMER REDUCTION WILL SATISFY YEAR ROUND *SO "REGULATORY TAP" = .2*(64.76)+.8*(64.21) = 64.3 * *PREMISE FOR NO BACKSLIDING OVERRIDES NO REGULATORY LIMITS *BASED ON API/NPRA SURVEY GASOLINE QUALITIES: *CG POOL (TAP=80.18; NOX=1343.7; VOC=1350.9) *CG/ETOH POOL ("ESTIMATED" TAP=75.5; NOX=1318.2; VOC=1552.5) *RFG REG (TAP=64.3; NOX=1248.9"REG"; VOC=1020.8"REG") *RFG PREM (TAP=64.3; NOX=1248.9"REG"; VOC=1020.8"REG")	*ABSENT BACKSLIDING DATA, USE BASELINE FACTORS: WINTER/SUMMER = 1540/1340 FOR NOX; 127.24/86.64 FOR TAP. *WINTER CG POOL (TAP=117.8; NOX=1544) *WINTER CG/ETOH POOL ("ESTIMATED" TAP=110.9; NOX=1514.9) *WINTER RFG REG (TAP=94.43; NOX=1516.9, A 1.5% REDUCTION) *WINTER RFG PREM (TAP=94.43; NOX=1516.9, A 1.5% REDUCTION)

1996 American Petroleum Institute/National Petroleum Refiners Association Survey of Refining Operations and Product Quality (API/NPRA, 1997).

For a given case, the model represents up to six gasolines (see Table 16).

All gasolines contain no more than 30 parts per million (ppm) sulfur, on average.

Gasoline properties are weighted to reflect the Class splits assumed in the National Petroleum Council (NPC) study of *U.S. Petroleum Refining* (NPC, 1993). Class splits account for differences in properties of gasolines produced for consumers in different climatic regions.

Specifications for products other than gasoline are based on the NPC study (NPC, 1993).

Table 16. Study case design						
Case	1	2	3	4	5	6
General	Reference	3% vol max MTBE	3% vol max MTBE	Reference	Ether Ban	Ether Ban
PADD	I+III	I+III	I+III	II	II	II
Year	2006	2006	2006	2006	2006	2006
Season	Sum	Sum	Win	Sum	Sum	Win
RFG oxygen wt%[a,b]	2.1-2.7	0-3.5 (E) <0.5 (M)	0-3.5(E) <0.5 (M)	2.1-3.5	0-3.5	0-3.5
CG oxygen wt%[a]	0-2.7	0-3.5	0-3.5	0-3.5	0-3.5	0-3.5
Vol% ethanol in CG[c]	N/A	10	10	10	10	10
Gasoline oxygenate	MTBE	EtOH MTBE	EtOH MTBE	EtOH MTBE	EtOH	EtOH
Gasoline pools[b]	CG-M CG-E RFG-M-R RFG-M-P RFG-E-R RFG-E-P	CG-M CG-E RFG-M-R RFG-M-P RFG-E-R RFG-E-P	CG-M CG-E RFG-M-R RFG-M-P RFG-E-R RFG-E-P	CG-M CG-E RFG-M-R RFG-M-P RFG-E-R RFG-E-P	CG-N CG-E RFG-N-R RFG-N-P RFG-E-R RFG-E-P	CG-N CG-E RFG-N-R RFG-N-P RFG-E-R RFG-E-P
RFG share	Current					
Economic premises	AEO Reference					
Ethanol cost	N/A	Vary	Vary	Vary	Vary	Vary
Other	Ratio-free refinery model/ low sulfur gasoline/ no toxics backsliding					

[a]Oxygen content in ethanol-containing gasoline is restricted to current tax incentive levels.
[b]R=regular grade; P=premium grade; E=containing ethanol; M=containing MTBE; N=containing no oxygenate.
[c]With RVP waiver (affects summer CG), assume that summer and winter CG-E contains 10 percent ethanol.

4.2 REFINERY RAW MATERIALS

Refinery inputs of crude oil and raw materials are based on *Petroleum Supply Annual 1998* (U.S. DOE, 1999a). Refinery inputs are projected to year 2006 by using the Reference Case growth rates published in the *Annual Energy Outlook 1999* (U.S. DOE, 1999b). The crude oil mix is based on the regional mixes reported by the NPC study (NPC, 1993).

4.3 PRODUCT REVENUE AND RAW MATERIAL COSTS

Revenues and costs are expressed in 1997 dollars. Raw material and crude oil costs are based on the *Annual Energy Outlook 1999* (U.S. DOE, 1999b), the NPC study (NPC, 1993), *Petroleum Marketing Annual* (U.S. DOE, 1999c), and requested guidance from the Energy Information Administration. Product prices are based on the *Annual Energy Outlook 1999* (U.S. DOE, 1999b), *Petroleum Marketing Annual* (U.S. DOE, 1999c), historical price differentials, price ratios, heating values, estimates reported by the NPC study (NPC, 1993), and requested guidance from the Energy Information Administration. Ethanol price is based on its octane value relative to gasoline, and it is assumed that there is a 0.3 percent increase in ethanol price with a 1 percent increase in volume. The ethanol price response does not affect estimation of the demand curves, which span a wide range of ethanol values. The demand curves will be used by other researchers who will apply more rigorous price elasticities of supply to determine supply/demand balance. This study reports the refiner/blender's net cost of ethanol, which includes allowance for federal tax exemptions.

4.4 FEDERAL TAX IMPLICATIONS FOR ETHANOL CONCENTRATIONS

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 three 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 at least 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 containing 5.7 or 7.7 percent ethanol (these blends correspond to the oxygen content standards for gasoline sold in ozone nonattainment and carbon monoxide 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 (U.S. GAO, 1997). In this ethanol demand study, it is assumed that the partial excise tax exemption is available for ethanol blended at 5.7, 7.7 or 10 percent.

4.5 REFINERY CAPACITY

Refinery capacity is based on in-place capacity and construction as reported in *Refinery Capacity Data 1999* (U.S. DOE, 1999d), the NPC study (NPC, 1993), the NPRA survey (NPRA, 1991), the *Oil & Gas Journal* (Radler, 1998 and 1999), or the survey report of American Petroleum Institute and NPRA (API/NPRA, 1997). Capacities for reformate splitter, FCC naphtha splitter, and straight run naphtha splitter are set at the greater of capacities reported in NPRA (NPRA, 1991) or in the NPC study (NPC, 1993). Refinery capacity for recovery of hydrogen is based on the API/NPRA survey (API/NPRA, 1997).

Process capacity investment is based on a 15 percent discounted cash flow rate of return on investment (ROI), and actual investment cost is based on a 10 percent ROI. For existing capacity, typical investment costs are used for up to 20 percent expansion in capacity. For capacity greater than the defined expansion limit, investment is subject to economies of scale, according to the "six-tenths factor" relationship:

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

New capacity and expansions are averaged over all refineries in a region. Investment options include long-established and widely used technologies, plus the more recently developed FCC naphtha desulfurization processes, such as CDTECH's CDHydro+CDH2S and the Mobil Oil Octgain 220 process, with performance and costs as reported by process licensors in the fall of 1998.

4.6 STUDY CASES

Study cases are summarized in Table 16. These cases estimate refinery demand curves for ethanol in a low sulfur gasoline world; with or without partial or full ether ban; and with or without an oxygen content specification. Only summer reference cases are examined, to estimate impacts for the most stressed season. Winter cases provide estimates of winter ethanol demand rather than impacts relative to a reference case. It is assumed that the 1 pound per square inch (psi) RVP waiver causes all ethanol-containing CG to have 10 percent ethanol.

The Reference Case 1 provides the basis for estimating the PADD I+III refinery process configuration in summer of year 2006, given Phase 2 gasoline and oxygen requirements; with no toxics backsliding relative to 1996; and without an oxygenate ban.

In Case 2, the refinery process configuration determined in Case 1 is used (with further investment allowed) to examine PADD I+III gasoline production in summer of year 2006, given Phase 2 gasoline requirements; with only an upper limit on oxygen content; with no toxics backsliding relative to 1996; and with a maximum allowable 3 volume (vol) percent MTBE in all gasoline.

In Case 3, the refinery process configuration determined in Case 2 is used (with no further investment allowed) to examine PADD I+III gasoline production in winter of year 2006, given Phase 2 gasoline requirements; with no toxics backsliding relative to 1996; and with a maximum allowable 3 vol percent MTBE in all gasoline.

The Reference Case 4 provides the basis for estimating the PADD II refinery process configuration in summer of year 2006, given Phase 2 gasoline and oxygen requirements; with no toxics backsliding relative to 1996; and without an oxygenate ban.

In Case 5, the refinery process configuration determined in Case 4 is used (with further investment allowed) to examine PADD II gasoline production in summer of year 2006, given Phase 2 gasoline requirements; with only an upper limit on oxygen content; with no toxics backsliding relative to 1996; and with a ban on MTBE.

In Case 6, the refinery process configuration determined in Case 5 is used (with no further investment allowed) to examine PADD II gasoline production in winter of year 2006, given Phase 2 gasoline requirements; with only an upper limit on oxygen content; with no toxics backsliding relative to 1996; and with a ban on MTBE.

5. THE DEMAND FOR ETHANOL USED IN U.S. REGIONAL OXYGENATE-LIMITED GASOLINE PRODUCTION IN YEAR 2006

5.1 READER GUIDANCE

This report's seasonal ethanol demand volumes are derived from model analysis of an average day in a particular season. The seasonal demand is multiplied by 365 for a year-based seasonal demand which is plotted in the figures. 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:

Annual demand = 5.5/12*(Summer demand, year-based) + 6.5/12*(Winter demand, year based).

The impacts of the winter-summer transition season are difficult to analyze and are not considered in this report.

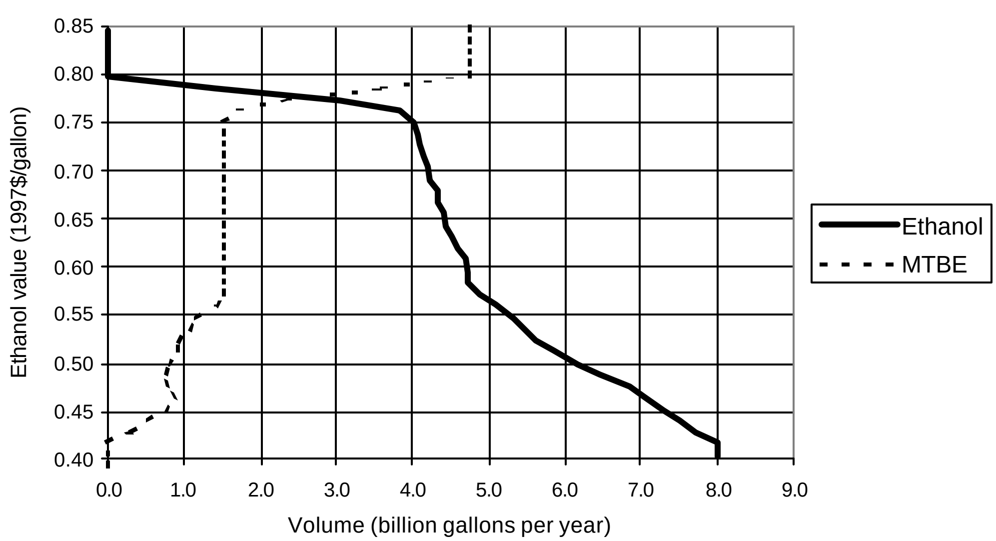
5.2 PADD I+III, SUMMER REFERENCE CONDITIONS

PADD I is a 17 state area in the U.S. East Coast, and PADD III consists of six states, most of which are located on the Gulf Coast. This study assumes that there are 74 operable refineries in these combined regions, which produce 56 percent of all gasoline manufactured in the United States.

The solid line in Fig. 1 shows the ORNL-RYM estimate of the demand curve for ethanol used in PADD I+III gasoline production in year 2006 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. Nevertheless, past studies have confirmed that individual case study results agree well with parametrically generated demand curves (Hadder, 1998).

The price responsive value of ethanol is an *illustrative* estimate of the price (and refiner value) of ethanol. It is assumed that the pre-tax price of ethanol increases 0.3 percent for each 1.0 percent increase in volume, relative to the reference price and volume for a given

Fig. 1. Oxygenate demand in Reference case PADD I+III gasoline production
Year 2006 summer - 30 ppm sulfur in gasoline



season and region. At $0.80 per gallon (the price responsive value), ethanol demand is zero. [Supply/demand crossover analysis is beyond the scope of this study. Such analysis can be done with the Ethanol Industry Evolution Systems Analysis Spreadsheet, a tool to examine the key determinants, costs, and growth characteristics of an evolving ethanol industry in the United States (TMS, 1998).]

At refiner values below $0.42 per gallon, ethanol demand is 8.0 BGY, and the ethanol concentration in the total gasoline pool is 10 vol percent. Fig. 1 shows how demand for MTBE, at a constant price, decreases as the price of ethanol falls. With an elastic MTBE price, the demand for MTBE would be greater and the demand for ethanol would be lower than shown in Fig. 1, as the value of ethanol falls. Consistent with prior work (Hadder, 1998), marginal cost results show that volatility limits make summer RFG more difficult and expensive to produce with high-RVP oxygenates like ethanol; ethanol's value in CG is enhanced by the 1 psi RVP waiver for 10 vol percent ethanol blends; and the demand for ethanol increases with sulfur reduction in gasoline (given the yield and octane losses premised for the model's gasoline sulfur reduction technologies).

Fig. 2 shows that, for summer Reference conditions, CG is the source of greatest demand for ethanol over the entire range of ethanol values. At maximum ethanol demand, RFG accounts for 25 percent of total demand for ethanol in gasoline blending. The disaggregation of demand in Fig. 2 will be useful in mapping ethanol production into ethanol demand regions, characterized on the basis of ozone non-attainment.

Key results for the summer Reference and all other cases are summarized in Tables 17 through 25, which show gasoline properties, blendstocks, refinery volume balances,

Table 17. Gasoline[a] properties			
	Case 1. Reference/PADD I+III/Sum		
	CG/ MTBE	RFG/MTBE	
		Reg	Prem
Volume, MBD	3802	879	395
Volume, %	74.9	17.3	7.8
Octane, (R+M)/2	88.7	88.2	94.2
RVP, psi	8.2	7.3	7.3
Aromatics, vol %	32.3	18.0	19.3
Benzene, vol %	1.83	0.95	0.95
Olefins, vol %	6.8	19.0	19.0
Sulfur, ppm	30	30	30
E200, %	55.3	59.7	59.7
E300, %	83.1	88.8	87.7
Oxygen, wt %	0.81	2.01	2.00
Specific gravity	.7464	.7274	.7294
Summer TAP, mg/mi	77.3[b]	57.4	57.9
NOx, mg/mi	1191	1242	1249[b]
VOC, mg/mi	1242	1026[b]	1025[b]

[a]Model had option to produce any of six gasoline types.
[b]Binding emissions constraint.

Table 17 (Continued). Gasoline properties

	Case 2. 3% vol max MTBE/PADD I+III/Sum					
	CG		RFG/MTBE		RFG/EtOH	
	MTBE	EtOH	Reg	Prem	Reg	Prem
Volume, MBD	3566	232	637	286	234	106
Volume, %	70.4	4.6	12.6	5.6	4.7	2.1
Octane, (R+M)/2	88.7	88.5	88.2	94.7	87.9	93.7
RVP, psi	8.2	9.2	6.9	7.0	7.3	7.1
Aromatics, vol %	33.4	26.0	22.5	26.3	24.3	23.8
Benzene, vol %	1.71	1.76	0.65	0.91	0.95	0.73
Olefins, vol %	8.0	3.8	19.0	9.5	17.7	19.0
Sulfur, ppm	30	30	30	30	30	29
E200, %	54.8	59.7	44.0	60.2	59.7	46.5
E300, %	83.5	90.6	82.0	87.3	89.3	87.8
Oxygen, wt %	0.54	3.53	0.55	0.55	3.50	3.47
Specific gravity	.7449	.7457	.7369	.7360	.7513	.7587
Summer TAP, mg/mi	77.3[a]	72.4[a]	61.6[a]	61.7[a]	61.6[a]	61.4[a]
NOx, mg/mi	1195	1175	1249[a]	1189	1249[a]	1249[a]
VOC, mg/mi	1241	1418	1024[a]	1026[a]	1025[a]	1024[a]

[a]Binding emissions constraint.

Table 17 (Continued). Gasoline[a] properties

	Case 3. 3% vol max MTBE/PADD I+III/Win				
	CG	RFG/MTBE		RFG/EtOH	
	MTBE	Reg	Prem	Reg	Prem
Volume, MBD	3557	279	125	651	292
Volume, %	72.5	5.7	2.6	13.3	6.0
Octane, (R+M)/2	88.8	88.7	94.4	87.3	93.2
RVP, psi	12.6	12.6	12.6	13.6	13.6
Aromatics, vol %	31.7	22.2	19.3	18.6	18.0
Benzene, vol %	1.81	0.77	0.92	0.95	0.86
Olefins, vol %	9.6	3.8	13.8	15.0	19.0
Sulfur, ppm	30	30	30	30	30
E200, %	59.7	60.2	59.7	59.6	59.7
E300, %	83.8	85.3	88.6	88.5	89.5
Oxygen, wt %	0.44	0.12	0.56	3.60	3.62
Specific gravity	.7354	.7214	.7201	.7313	.7261
Winter TAP, mg/mi	113.4[b]	90.6[b]	90.4[b]	90.6[b]	90.4[b]
NOx, mg/mi	1371	1326	1359	1363	1413

[a]Model had option to produce any of six gasoline types.
[b]Binding emissions constraint.

Table 17 (Continued). Gasoline[a] properties				
	Case 4. Reference/PADD II/Sum			
	CG		RFG/EtOH	
	MTBE	EtOH	Reg	Prem
Volume, MBD	1264	450	252	113
Volume, %	61	22	12	5
Octane, (R+M)/2	89.3	88.4	87.6	92.6
RVP, psi	8.5	9.5	7.2	7.4
Aromatics, vol %	31.7	32.0	27.3	20.7
Benzene, vol %	1.95	1.70	0.95	0.95
Olefins, vol %	7.0	3.8	15.9	19.0
Sulfur, ppm	30	30	30	23
E200, %	59.7	59.7	59.7	59.7
E300, %	84.6	88.6	88.4	89.0
Oxygen, wt %	0.17	3.49	3.51	3.57
Specific gravity	.7402	.7545	.7487	.7364
Summer TAP, mg/mi	80.2[b]	75.5[b]	62.6	60.5
NOx, mg/mi	1196	1189	1238	1248
VOC, mg/mi	1267	1476	1021[b]	1021[b]

[a]Model had option to produce any of six gasoline types.
[b]Binding emissions constraint.

Table 17 (Continued). Gasoline[a] properties				
	Case 5. Ether Ban/PADD II/Sum			
	CG		RFG/EtOH	
	MTBE	EtOH	Reg	Prem
Volume, MBD	1235	478	252	113
Volume, %	59	23	12	5
Octane, (R+M)/2	89.4	88.4	87.6	92.0
RVP, psi	8.5	9.5	7.2	7.0
Aromatics, vol %	32.5	30.5	27.7	33.0
Benzene, vol %	1.88	1.77	0.95	0.95
Olefins, vol %	6.5	8.1	14.8	6.8
Sulfur, ppm	30	30	30	30
E200, %	59.7	59.7	59.2	60.2
E300, %	84.2	88.6	88.4	89.3
Oxygen, wt %	0.00	3.49	3.52	3.47
Specific gravity	.7391	.7545	.7480	.7587
Summer TAP, mg/mi	80.2[b]	75.6[b]	62.6	63.9
NOx, mg/mi	1196	1195	1226	1186
VOC, mg/mi	1273	1463	1021[b]	1022[b]

[a]Model had option to produce any of six gasoline types.
[b]Binding emissions constraint.

Table 17 (Continued). Gasoline properties

	Case 6. Ether Ban/PADD II/Win					
	CG		RFG/MTBE		RFG/EtOH	
	MTBE	EtOH	Reg	Prem	Reg	Prem
Volume, MBD	1206	566	15	7	221	99
Volume, %	57	27	0.7	0.3	10	5
Octane, (R+M)/2	89.6	88.7	87.3	92.6	87.3	92.0
RVP, psi	13.1	14.1	13.1	13.1	14.1	14.1
Aromatics, vol %	30.1	24.2	23.0	27.0	26.0	26.2
Benzene, vol %	2.10	2.44	0.69	0.47	0.95	0.95
Olefins, vol %	5.6	6.2	19.0	19.0	15.6	6.8
Sulfur, ppm	30	30	30	30	30	30
E200, %	59.7	59.7	60.2	59.9	59.7	59.7
E300, %	84.2	91.5	82.0	85.5	91.9	86.4
Oxygen, wt %	0.00	3.56	0.00	0.00	3.60	3.56
Specific gravity	.7279	.7383	.7271	.7290	.7312	.7379
Winter TAP, mg/mi	117.6[a]	110.8[a]	94.5[a]	94.6[a]	94.6[a]	94.4[a]
NOx, mg/mi	1353	1328	1450	1462	1401	1340

[a]Binding emissions constraint.

Table 18. Gasoline[a] blendstocks
(percent)

	Case 1. Reference/PADD I+III/Sum		
	CG/ MTBE	RFG/MTBE	
		Reg	Prem
C4s	1.6	0.8	0.8
Reformate	34.3	23.0	19.8
Straight run naphtha	2.6	4.4	
C5+ isomerate	10.7		
FCC naphtha	4.8	26.5	24.1
Desulfurized FCC naphtha	26.0	4.1	
Coker naphtha			
Hydrocrackate	8.1	11.6	
Alkylate	7.4	18.5	42.2
Polymer gasolines			1.3
Dimate			0.9
MTBE	4.5	10.9	10.8
Ethanol			
Natural gasoline			

[a]Model had option to produce any of six gasoline types.

Table 18 (Continued). Gasoline blendstocks (percent)						
	Case 2. 3% vol max MTBE/PADD I+III/Sum					
	CG		RFG/MTBE		RFG/EtOH	
	MTBE	EtOH	Reg	Prem	Reg	Prem
C4s	1.2	0.8	0.8	0.8	0.8	0.8
Reformate	33.5	28.4	17.2	32.1	28.8	32.5
Straight run naphtha	2.6	1.4	1.2		13.2	4.0
C5+ isomerate	11.8	5.0				
FCC naphtha	6.6		26.3	16.6	25.1	14.1
Desulfurized FCC naphtha	24.8	23.2	23.0		10.0	2.5
Coker naphtha						
Hydrocrackate	8.6	28.1				
Alkylate	7.1	1.0	28.4	47.5	15.7	29.8
Polymer gasolines	0.6	2.0			6.5	6.3
Dimate	0.1					
MTBE	3.0		3.0	3.0		
Ethanol		10.0			10.0	10.0
Natural gasoline						

Table 18 (Continued). Gasoline[a] blendstocks (percent)					
	Case 3. 3% vol max MTBE/PADD I+III/Win				
	CG	RFG/MTBE		RFG/EtOH	
	MTBE	Reg	Prem	Reg	Prem
C4s	9.0	10.8	9.7	8.3	7.7
Reformate	34.7	19.1	27.9	16.0	10.4
Straight run naphtha	3.3			3.4	
C5+ isomerate	10.7			5.1	
FCC naphtha	11.1	1.3	10.5	5.4	9.6
Desulfurized FCC naphtha	17.6	28.2		39.5	26.7
Coker naphtha					
Hydrocrackate	8.2	10.1	2.6	1.1	
Alkylate	2.8	29.6	46.2	6.5	30.6
Polymer gasolines				4.9	5.0
Dimate	0.1	0.2			
MTBE	2.4	0.6	3.0		
Ethanol				10.0	10.0
Natural gasoline	0.1				

[a]Model had option to produce any of six gasoline types.

Table 18 (Continued). Gasoline[a] blendstocks (percent)				
	Case 4. Reference/PADD II/Sum			
	CG		RFG/EtOH	
	MTBE	EtOH	Reg	Prem
C4s	2.2	1.4	0.8	0.8
Reformate	36.2	34.2	19.8	15.4
Straight run naphtha	3.4	5.5	3.5	
C5+ isomerate	8.8	13.1	16.4	
FCC naphtha	5.7	2.9	21.5	31.2
Desulfurized FCC naphtha	18.7	24.5	15.6	
Coker naphtha				
Hydrocrackate	7.6	6.6	9.4	2.8
Alkylate	16.1			36.6
Polymer gasolines			3.1	3.2
Dimate	0.3			
MTBE	0.9			
Ethanol		10.0	10.0	10.0
Natural gasoline		1.7		

[a]Model had option to produce any of six gasoline types.

Table 18 (Continued). Gasoline[a] blendstocks (percent)				
	Case 5. Ether Ban/PADD II/Sum			
	CG		RFG/EtOH	
	MTBE	EtOH	Reg	Prem
C4s	2.0	1.6	0.8	0.8
Reformate	34.5	35.5	20.2	30.3
Straight run naphtha	3.9	5.3	2.8	
C5+ isomerate	9.5	10.9	16.5	
FCC naphtha	5.8	3.5	23.5	10.8
Desulfurized FCC naphtha	20.1	21.5	13.7	16.2
Coker naphtha				
Hydrocrackate	7.6	5.5	9.7	13.9
Alkylate	16.6	2.0		18.1
Polymer gasolines		0.8	2.9	
Dimate		0.9		
MTBE				
Ethanol		10	10	10
Natural gasoline		2.5		

[a]Model had option to produce any of six gasoline types.

Table 18 (Continued). Gasoline blendstocks (percent)						
	Case 6. Ether Ban/PADD II/Win					
	CG		RFG/MTBE		RFG/EtOH	
	MTBE	EtOH	Reg	Prem	Reg	Prem
C4s	9.6	11.7	10.3	10.1	12.0	10.9
Reformate	36.1	25.2	20.0	23.3	19.4	13.5
Straight run naphtha		2.5	4.3	8.6	10.4	0.1
C5+ isomerate	13.8	0.7			13.5	
FCC naphtha	7.2	0.4		2.7	30.5	1.7
Desulfurized FCC naphtha	14.1	29.0	39.8	14.9	2.1	40.6
Coker naphtha						
Hydrocrackate	6.7	13.2			1.7	
Alkylate	12.4	5.4	10.8	24.5		23.3
Polymer gasolines		1.9				
Dimate			14.8	15.8	0.4	
MTBE						
Ethanol		10.0			10.0	10.0
Natural gasoline						

Table 19. Pooled gasoline[a] blendstocks (percent)			
Blendstock	Case		
	1. Reference/PADD I+III/Sum	2. 3% vol max MTBE/ PADD I+III/Sum	3. 3% vol max MTBE/ PADD I+III/Win
C4s	1.4	1.1	8.9
Reformate	31.2	30.9	29.7
Straight run naphtha	2.7	2.8	2.8
C5+ isomerate	8.0	8.5	8.4
FCC naphtha	10.1	10.4	9.7
Desulfurized FCC naphtha	20.2	21.5	21.2
Coker naphtha			
Hydrocrackate	7.2	7.3	6.7
Alkylate	12.1	12.6	7.6
Polymer gasolines	1.0	1.0	0.9
Dimate	0.1	0.1	0.1
MTBE	6.1	2.7	1.9
Ethanol		1.1	1.9
Natural gasoline			0.1

[a]Model had option to produce any of six gasoline types.

Table 19 (Continued). Pooled gasoline[a] blendstocks
(percent)

Blendstock	Case		
	4. Reference/PADD II/Sum	5. Ether Ban/PADD II/Sum	6. Ether Ban/PADD II/Win
C4s	1.8	1.7	10.5
Reformate	32.7	32.7	30.2
Straight run naphtha	3.7	3.9	1.9
C5+ isomerate	10.1	10.1	9.5
FCC naphtha	8.4	7.7	7.5
Desulfurized FCC naphtha	18.5	19.4	18.2
Coker naphtha			
Hydrocrackate	7.4	7.7	7.5
Alkylate	11.8	11.3	9.8
Polymer gasolines	0.5	0.5	0.5
Dimate	0.2	0.2	0.2
MTBE	0.6		
Ethanol	3.9	4.1	4.2
Natural gasoline	0.4	0.6	

[a]Model had option to produce any of six gasoline types.

Table 20. Refinery volume balance
(Thousand barrels per day)

	Case		
	1. Reference/PADD I+III/Sum	2. 3% vol max MTBE/PADD I+III/Sum	3. 3% vol max MTBE/PADD I+III/Win
Purchased inputs:			
Crude oils	9,299.2	9,396.5	9,009.0
Ethanol	0.0	57.4	94.2
Methanol	33.7	33.7	31.3
MTBE	210.2	36.0	0.0
Other raw materials	288.6	361.7	441.0
Total purchased inputs	9,831.7	9,885.3	9,575.5
Total products	10,038.6	10,094.5	9,813.8

Table 20 (Continued). Refinery volume balance (Thousand barrels per day)			
	Case		
	4. Reference/PADD II/Sum	5. Ether Ban/PADD II/Sum	6. Ether Ban/PADD II/Win
Purchased inputs:			
Crude oils	3,688.4	3,702.7	3,621.9
Ethanol	81.4	84.2	88.5
Methanol	4.0	0.0	0.0
MTBE	0.0	0.0	0.0
Other raw materials	150.9	140.8	274.5
Total purchased inputs	3,924.7	3,927.7	3,984.9
Total products	3,986.1	3,994.5	4,065.5

Table 21. Hydrogen balance for refineries
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 x 100 percent)

Process	Case		
	1. Reference/PADD I+III/Sum	2. 3% vol max MTBE/PADD I+III/Sum	3. 3% vol max MTBE/PADD I+III/Win
Naphtha hydrotreating	-9,507 (92)	-9,702 (94)	-9,241 (86)
FCC gasoline desulfurization	-2,595 (92)	-2,754 (98)	-2,626 (88)
Distillate desulfurization	-19,266 (83)	-17,974 (81)	-19,609 (84)
Resid desulfurization	-7,226 (92)	-7,226 (92)	-6,912 (88)
FCC feed hydrofining	-17,759 (92)	-17,751 (92)	-17,058 (88)
Gas oil hydrocracking	-80,139 (87)	-81,058 (87)	-72,430 (81)
Resid hydrocracking	-11,836 (87)	-13,807 (101)	-12,853 (81)
Reforming	+96,203 (89)	+98,547 (91)	+90,695 (80)
C4 isomerization	-176 (89)	-176 (89)	-168 (85)
C5/C6 isomerization	-838 (90)	-890 (95)	-850 (85)
Ether production	-770 (87)	-770 (87)	-716 (81)
Hydrogen production	+71,127 (89)	+71,200 (89)	+68,000 (85)
Hydrogen to fuel and losses	-17,220	-17,640	-16,234

Table 21 (Continued). Hydrogen balance for refineries
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 x 100 percent)

Process	Case		
	4. Reference/PADD II/Sum	5. Ether Ban/PADD II/Sum	6. Ether Ban/PADD II/Win
Naphtha hydrotreating	-3,929 (79)	-3,954 (80)	-3,774 (75)
FCC gasoline desulfurization	-995 (87)	-1,040 (91)	-963 (83)
Distillate desulfurization	-12,848 (84)	-12,843 (84)	-13,514 (84)
Resid desulfurization	-1,569 (87)	-1,569 (87)	-1,497 (83)
FCC feed hydrofining	-6,354 (60)[a]	-5,533 (53)[a]	-4,326 (42)[a]
Gas oil hydrocracking	-28,347 (72)	-29,721 (75)	-26,670 (74)
Reforming	+44,670 (76)	+45,424 (87)	+41,386 (70)
C4 isomerization	-38 (84)	-38 (84)	-36 (80)
C5/C6 isomerization	-434 (84)	-434 (84)	-414 (80)
Ether production	-90 (84)	0 (0)	0 (0)
Hydrogen production	+23,335 (101)	+23,335 (84)	+22,224 (80)
Hydrogen to fuel and losses	-13,401	-13,627	-12,415

[a] In model, process economics favor high sulfur feed to advanced FCC naphtha desulfurization. In long-run analysis, this results in lower utilization or retirement of process capacity (e.g., FCC feed hydrofining) which would otherwise produce lower sulfur FCC naphthas.

Table 22. Process capacity expansions and additions (MBCD)[a]

Relative to Reference Cases

Process	Case			
	2. 3% vol max MTBE/PADD I+III/Sum	3. 3% vol max MTBE/PADD I+III/Win	5. Ether Ban/PADD II/Sum	6. Ether Ban/PADD II/Win
Crude distillation	73	None		None
Naphtha hydrotreating	53			
FCC naphtha fractionation				
FCC naphtha desulfurization	65		19	
Reforming	69			
Fluid catalytic cracking	193			
Resid cracking	31			
Alkylation	26			
C5/C6 isomerization	26			
Hydrogen plant, FOE				
Sulfur, tons per day	0.4			

[a]Investment decisions are based on a 15 percent discounted cash flow return on investment.

Table 23. Cost of process capacity expansions and additions ($MM)[a]

Relative to Reference Cases

Process	Case			
	2. 3% vol max MTBE/PADD I+III/Sum	3. 3% vol max MTBE/ PADD I+III/Win	5. Ether Ban/PADD II/Sum	6. Ether Ban/PADD II/Win
Crude distillation	131	None		None
Naphtha hydrotreating	75			
FCC naphtha fractionation				
FCC naphtha desulfurization	93		32	
Reforming	217			
Fluid catalytic cracking	939			
Resid cracking	426			
Alkylation	182			
C5/C6 isomerization	142			
Hydrogen plant, FOE				
Sulfur, tons per day	103			
Land, buildings, catalyst, chemical, spares, environmental, other	233		3	
Total	2,541	0	35	0

[a]Investment decisions are based on a 15 percent discounted cash flow return on investment.

Table 24. Components of refinery cost changes (cents per gallon of RFG) Relative to Reference Cases				
	Case			
	2. 3% vol max MTBE/PADD I+III/Sum	3. 3% vol max MTBE/PADD I+III/Win	5. Ether Ban/PADD II/Sum	6. Ether Ban/PADD II/Sum
Raw material costs and product revenue changes[a]	-1.5	No Base Case	+1.6	No Base Case
Processing costs	+0.7		-1.5	
Capital charges	+2.0		+0.1	
Fixed operating costs	+0.7		+0.05	
Total cost change (10 percent ROI)	+1.9		+0.3	

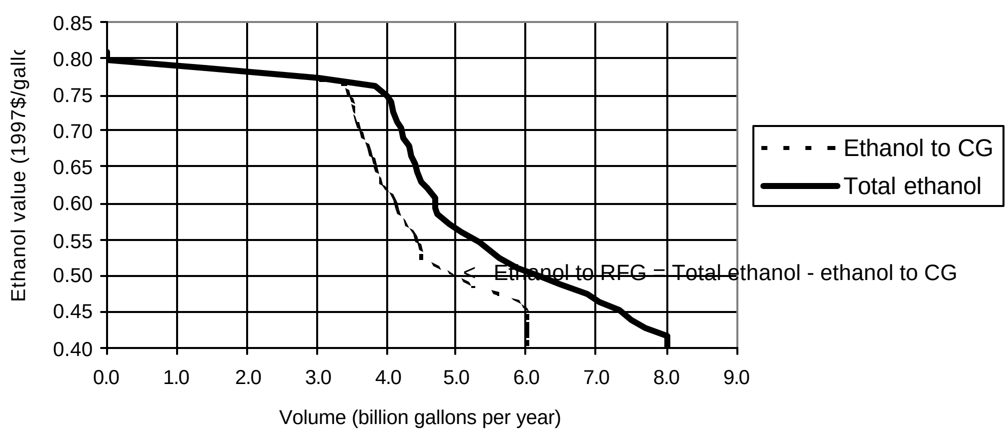
Table 25. Quality of crude oil			
Property	Case		
	1. Reference/PADD I+III/Sum	2. 3% vol max MTBE/PADD I+III/Sum	3. 3% vol max MTBE/PADD I+III/Win
Sulfur content, wt %	1.34	1.34	1.34
Gravity, °API	30.9	30.9	30.9

Table 25 (Continued). Quality of crude oil

Property	Case		
	4. Reference/PADD II/Sum	5. Ether Ban/PADD II/Sum	6. Ether Ban/PADD II/Win[a]
Sulfur content, wt %	1.37	1.37	1.34
Gravity, °API	32.6	32.6	30.9

[a]Crude misspecification in Case 8 does not materially affect results. Sulfur misspecification is well within variability of source data.

Fig. 2. Ethanol demand in Reference case PADD I+III gasoline type production
Year 2006 summer - 30 ppm sulfur in gasoline



hydrogen balances, example process utilizations, investments, refinery cost changes, and crude oil qualities.

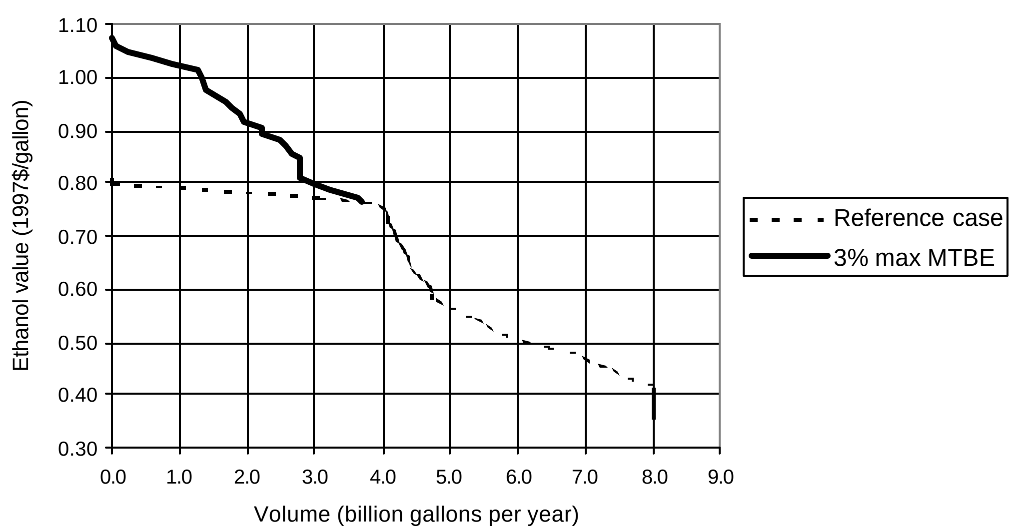
5.3 PADD I+III, SUMMER WITH 3 PERCENT MAXIMUM MTBE

MTBE is the dominant oxygenate in RFG produced in PADD I+III refineries. DOE (U.S. DOE, 1994) has shown that, without an oxygen use requirement, refiners would still choose to use a significant amount of oxygen in gasoline. A more recent PADD I study (Hadder, 2000) estimates that MTBE use without an oxygenate requirement would not be much less than current use, suggesting that gasoline production has evolved to depend on the attractive octane and volatility characteristics of MTBE. DOE has reported that elimination of MTBE (280,000 thousand barrels per day) is equivalent to a loss of up to 400,000 barrels per day of gasoline production, which is about 5 percent of the U.S. gasoline supply and equivalent to the output of four to five large refineries (Mazur, 2000). A substantial portion of lost gasoline production is due to the octane-yield trade-offs for replacement blendstocks (Hadder, 2000).

Allowing a small percentage of MTBE in gasoline could have significant benefits. A 3 vol percent limit on MTBE would reduce the likelihood for MTBE/water contact; increase the ethanol market; give refiners the option for limited use of MTBE to achieve octane and summer volatility targets and increased flexibility in the transition from winter to summer; and provide greater assurance of adequate gasoline supplies. The solid line in Fig. 3 shows the demand curve for ethanol used in PADD I+III summer gasoline production with 3 vol percent maximum MTBE and no minimum oxygen requirement. At $1.02 per gallon (the price responsive value), ethanol demand is 0.9 BGY, compared

with zero demand in the summer Reference case. With the limitation on MTBE, ethanol demand is substantially higher than the summer Reference case demand until the ethanol value falls to $0.76 per gallon, below which the demand curves are similar.

Fig. 3. Ethanol demand with reduced MTBE in PADD I+III gasoline production
Year 2006 summer - 3% max MTBE - 30 ppm sulfur in gasoline

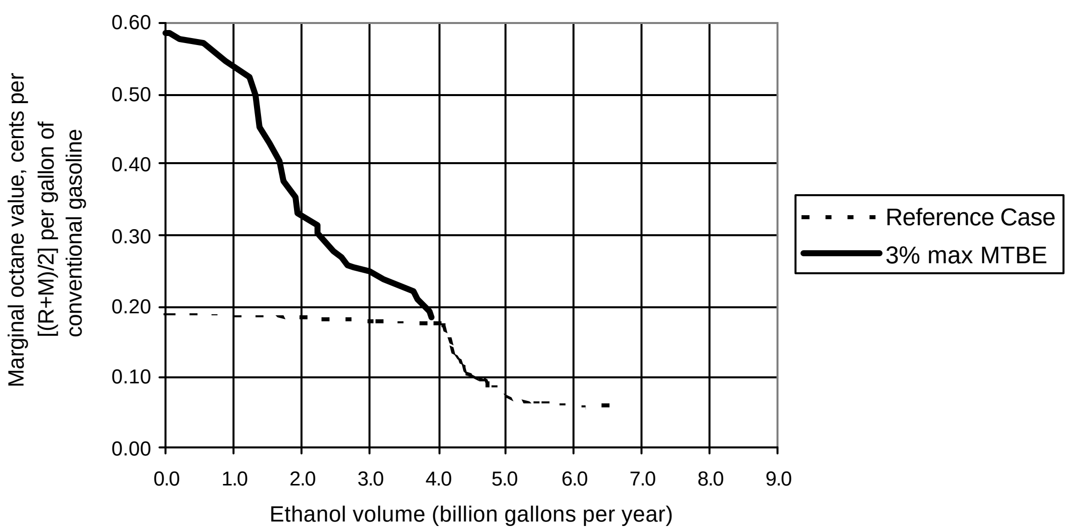


Tables 17 through 22 show key processing and blending impacts. The MTBE volume loss is compensated by increased ethanol blending and increased processing of crude oil and other raw materials, principally purchased gas oil. With increased crude and gas oil processing, there is an increase in FCC naphtha, which has to be desulfurized to satisfy the gasoline sulfur specification. The MTBE octane loss is compensated by increased percentages of ethanol, isomerate, and alkylate blended to gasoline. Capacity expansions are required for processes including crude distillation, FCC, FCC naphtha desulfurization, alkylation, isomerization, and sulfur recovery. Reformer expansion increases reformate octane, at some expense of yield. Increased TAP emissions, related to reformate blending, takes up all the summer Reference case slack (in gasolines with some giveaway beyond the no backsliding requirement in the TAP constraints).

The reduction of MTBE results in a cost increase of 1.9 cents per gallon of RFG (Table 24), with investment being the largest component of cost increase. Total investment is $2.5 billion, or about $30 million per refinery, on average. Compared to a ban, a 3 percent allowance for blending MTBE to gasoline substantially reduces refining costs. Based on marginal costs, the cost of a ban would be at least 3.1 cents per gallon of RFG. For comparison, the MathPro study (MathPro, 2000) estimates the cost of an MTBE ban in PADD I+III, with no TAP backsliding, and with no oxygen requirement, at 3 cents per gallon of summer RFG and oxygenated gasoline.

Marginal costs show that the major contributors to increased costs for reduced use or ban of MTBE are control of octane, volatility, and TAP. For example, Fig. 4 shows how much greater the octane value becomes when the allowable MTBE is reduced to 3 percent.

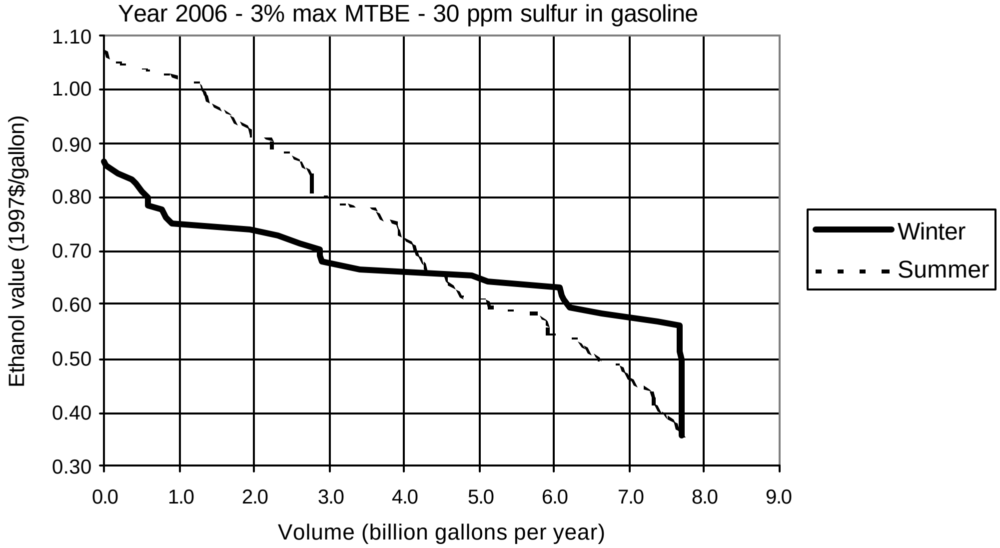
Fig. 4. Octane value in PADD I+III gasoline production
Year 2006 summer - 30 ppm sulfur in gasoline



5.4 PADD I+III, WINTER WITH 3 PERCENT MAXIMUM MTBE

The solid line in Fig. 5 shows the demand curve for ethanol used in PADD I+III winter gasoline production with 3 vol percent maximum MTBE. At $0.84 per gallon (the price responsive value), ethanol demand is 0.2 BGY, considerably lower than the summer ethanol demand of 0.9 BGY at its price-responsive value of $1.02 per gallon. When ethanol value falls below $0.65 per gallon, then the winter ethanol demand exceeds summer demand until gasolines are at the maximum allowable limits for ethanol.

Fig. 5. Seasonal ethanol demand with reduced MTBE in PADD I+III gasoline production
Year 2006 - 3% max MTBE - 30 ppm sulfur in gasoline



Among the factors that explain the seasonal differences in ethanol demand is the low sulfur requirement for gasoline. Sulfur reduction and octane numbers are more costly in summer than in winter. Winter gasoline blending takes advantage of substantial butane blending to maintain octane and control sulfur. Fig. 6 shows how the seasonal demands change if there is no requirement for low sulfur gasoline. Compared to Fig. 5, the differences in season demand have been significantly reduced at higher ethanol values.

As MTBE is reduced, more C4s (butane and related 4-carbon molecules) become available. Because of high vapor pressure, C4s can be blended into winter gasoline but not into summer gasoline. Absent conversion of MTBE plants to production technologies that utilize isobutylene, ethanol is the primary substitute for MTBE in the summer.

However, in the winter, ethanol may have to compete with directly-blended C4s. Fig. 7 shows how C4 blendstocks increase as ethanol value increases. *These results suggest that a reduction of MTBE may not have an equivalent increase in ethanol demand in the wintertime.*

Fig. 6. Seasonal ethanol demand with reduced MTBE in PADD I+III production of gasoline with no low sulfur requirement
Year 2006 -3% max MTBE

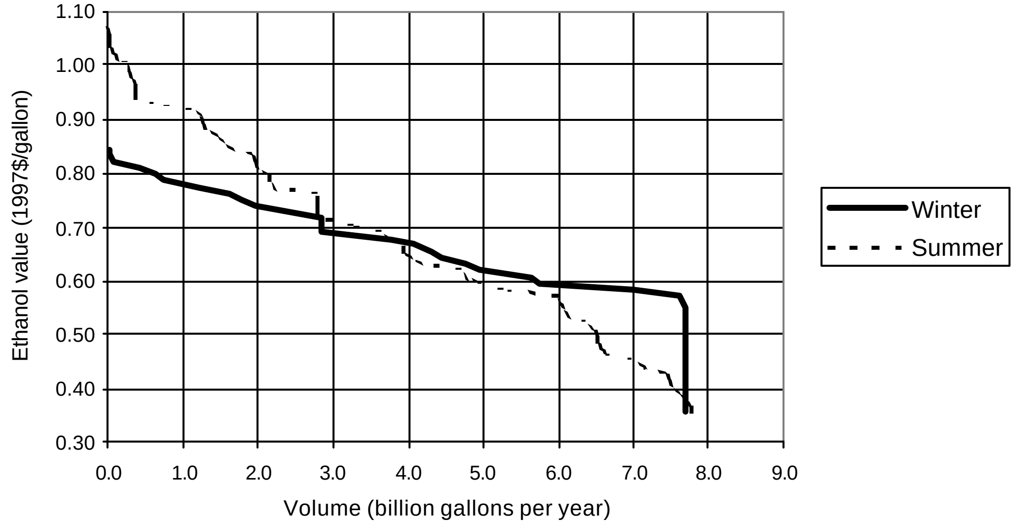
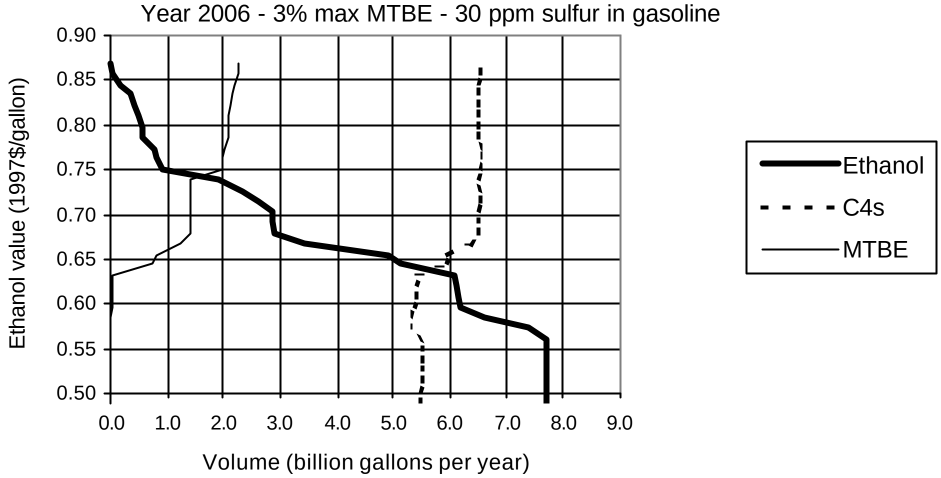


Fig. 7. Blendstock tradeoffs with reduced MTBE in PADD I+III winter gasoline production
Year 2006 - 3% max MTBE - 30 ppm sulfur in gasoline



5.5 PADD I+III, ANNUAL WITH 3 PERCENT MAXIMUM MTBE

It is assumed that the summer season is 5.5 months long and the winter season is 6.5 months long. With due consideration for different season lengths and different gasoline production within seasons, Fig. 8 shows the annualized demand for ethanol used in PADD I+III gasoline production, with 3 percent maximum MTBE.

Fig. 8. Annual ethanol demand with reduced MTBE in PADD I+III gasoline production
Year 2006 - 3% max MTBE - 30 ppm sulfur in gasoline

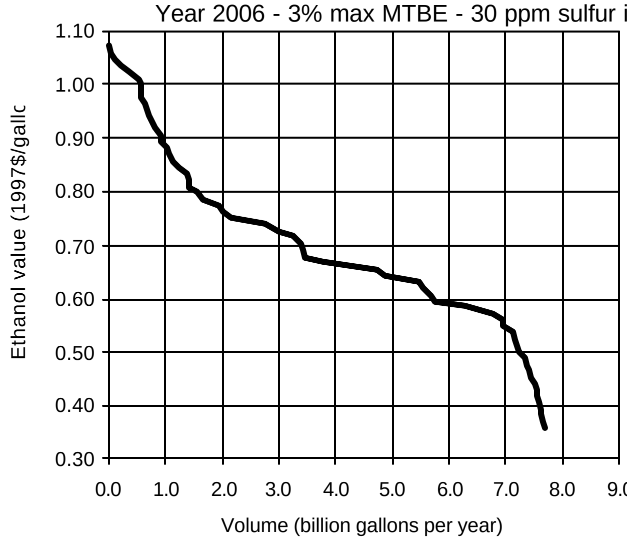
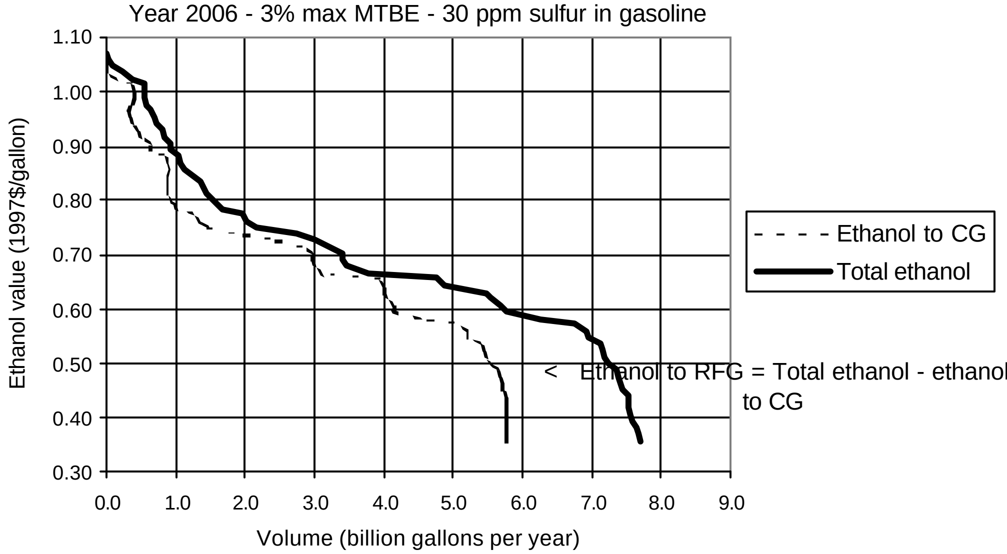


Fig. 9 shows that, with 3 percent maximum MTBE, CG is the source of greater demand for ethanol over the entire range of ethanol values. At $0.40 per gallon, with gasolines containing almost the maximum allowable 10 vol percent of ethanol, RFG accounts for 24 percent of total ethanol demand in gasoline blending. The disaggregation of demand in Fig. 9 will be useful in mapping ethanol production into ethanol demand regions, characterized on the basis of ozone non-attainment.

Fig. 9. Annual ethanol demand with reduced MTBE in PADD I+III gasoline type production
Year 2006 - 3% max MTBE - 30 ppm sulfur in gasoline



5.6 PADD II, SUMMER REFERENCE CONDITIONS

PADD II is a 15 state area in the U.S. Midwest. This study assumes that PADD II has 29 operable refineries which produce 23 percent of all gasoline manufactured in the United States.

The solid line in Fig. 10 shows the ORNL-RYM estimate of the demand curve for ethanol used in PADD II gasoline production in year 2006 for summer reference conditions. At $0.72 (the price responsive value), ethanol demand is 1.2 BGY. Ethanol demand is 3.2 BGY at refiner values below $0.58 per gallon, and the ethanol concentration in the total gasoline pool is 10 vol percent. Fig. 10 shows how demand for MTBE, at a constant price, decreases as the price of ethanol falls. With an elastic MTBE price, the demand for MTBE would be greater and the demand for ethanol would be lower than shown in Fig. 10, as the value of ethanol falls. Marginal cost results for this PADD II case suggest that volatility limits make summer RFG more difficult to produce with high-RVP oxygenates like ethanol; ethanol's value in CG is enhanced by the 1 psi RVP waiver for 10 vol percent ethanol blends; and the demand for ethanol increases with reductions in allowable sulfur in gasoline (given the yield and octane losses premised for the model's gasoline sulfur reduction technologies).

Fig. 10. Oxygenate demand in Reference case PADD II gasoline production
Year 2006 summer - 30 ppm sulfur in gasoline

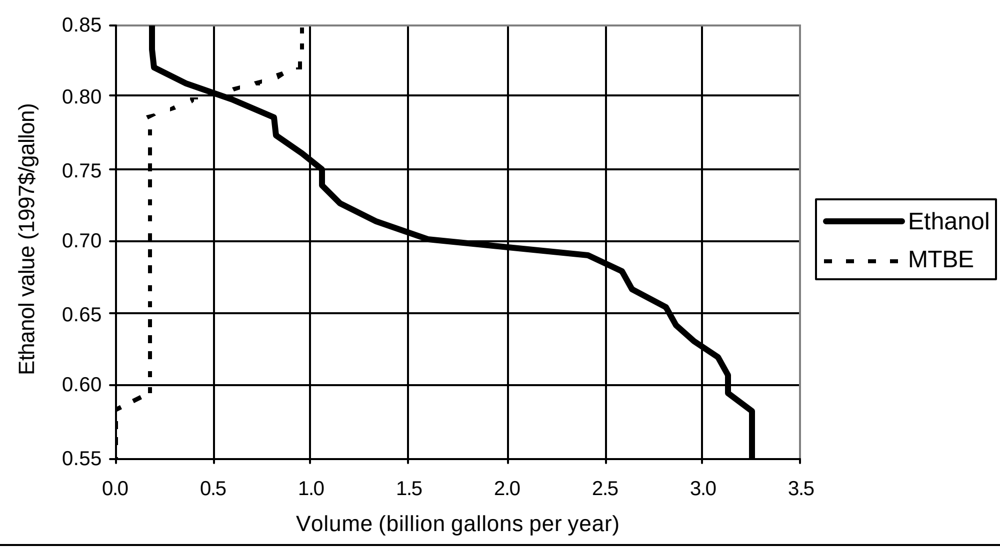
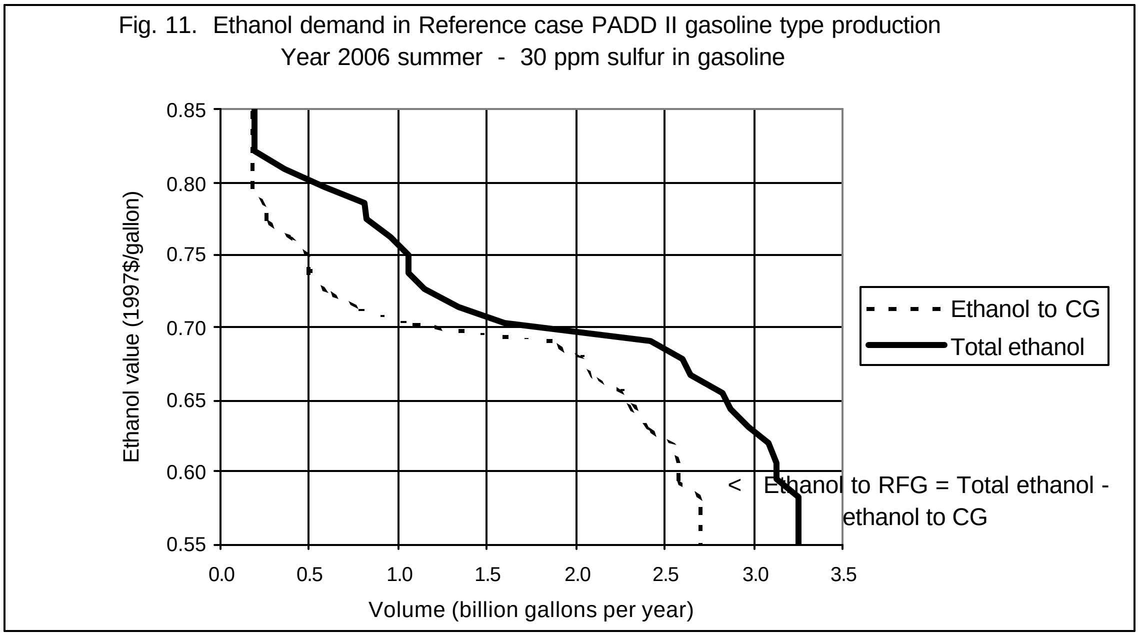


Fig. 11 shows that, for summer Reference conditions, CG provides the greatest demand potential for ethanol over the entire range of ethanol values. At $0.58 per gallon, gasolines contain the maximum allowable 10 vol percent of ethanol, and RFG accounts for 17 percent of total ethanol demand in gasoline blending. The disaggregation of demand in Fig. 11 will be useful in mapping ethanol production into ethanol demand regions, characterized on the basis of ozone non-attainment.

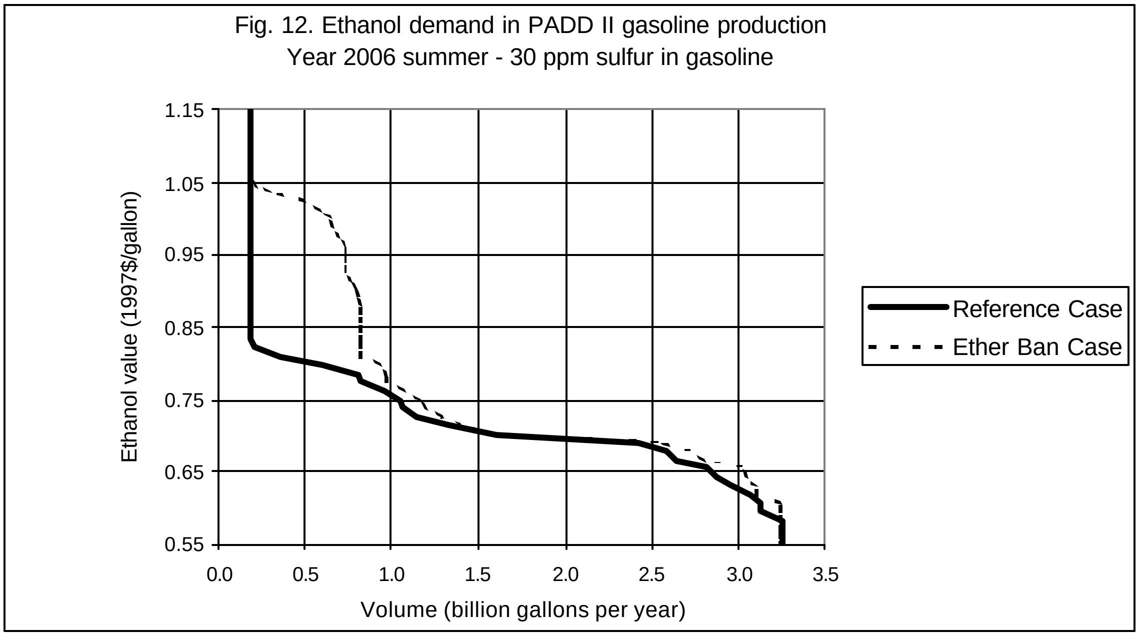


5.7 PADD II, SUMMER WITH MTBE BAN

PADD II has the highest regional use of ethanol. Ethanol is at least 90 percent of the total oxygenate volume now blended to gasoline in PADD II. Furthermore, the production share of RFG in PADD II is a relatively low 17 percent. Therefore, over some of ethanol's value range, an MTBE ban should not result in substantially different ethanol demand compared to either the summer Reference case or to a 3 vol percent MTBE case. *In fact, in Fig. 10, the Reference case curves below $0.78 per gallon are identical to curves for a 3 vol percent maximum MTBE case.* Below this value of ethanol in the summer Reference case, MTBE used in any gasoline is less than 3 vol percent.

The dashed line in Fig. 12 shows the demand curve for ethanol used in PADD II summer gasoline production with an MTBE ban. At $0.73 per gallon (the price responsive value), ethanol demand is 1.3 BGY, compared with 1.2 BGY at the price responsive value ($0.72) in the summer Reference case. With the MTBE ban, ethanol demand is substantially higher than the summer Reference case demand until the value of ethanol falls below $0.72 per gallon, where the ethanol volume in the ban is slightly higher until its concentration reaches 10 vol percent. The demand curve at or below the price responsive value suggests that there will be little difference in ethanol demand in a 3 vol percent MTBE case and an MTBE ban case.

Tables 17 through 22 show key processing and blending impacts. The MTBE volume loss is compensated by increased processing of crude oils and increased ethanol blending. The MTBE octane loss is compensated by increased percentages of ethanol and by higher-octane reformate blended to gasoline. The severity of reformer operation has



increased, with a 2 percent increase in pool Research Octane Number, and a 1 percent increase in pool aromatics. Reformate has lower vapor pressure and sulfur content compared with alkylate. There is a substantial increase, compared to the summer Reference case, in reformate blended to RFG premium with ethanol; the TAP property of this gasoline has headroom to accommodate additional reformate, which has higher TAP emissions than alkylate. Isobutylene is diverted from the shut-down ether plant to alkylation. Nevertheless, because of the strategy to maintain octane with reformate (taking advantage of vapor pressure and sulfur benefits), there is a slight reduction in alkylate blended to the gasoline pool, and a substantial reduction of alkylate blended to RFG premium with ethanol. Lastly, with the increase in crude oil processing, a small capacity expansion is required for FCC naphtha desulfurization.

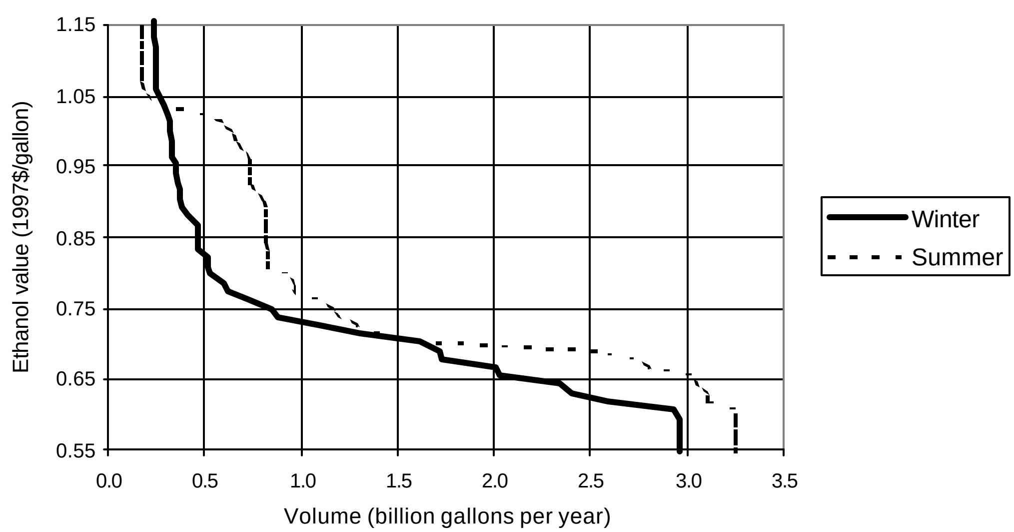
At the price-responsive cost, the MTBE ban results in a cost increase of 0.3 cents per gallon of RFG (Table 24), with raw materials being the largest component of cost increase. For a 3 vol percent MTBE case, there would be no cost increase since the case would be identical to the Reference case.

5.8 PADD II, WINTER WITH MTBE BAN

The solid line in Fig. 13 shows the demand curve for ethanol used in PADD II winter gasoline production with an MTBE ban. At $0.71 per gallon (the price responsive value), ethanol demand is 1.4 BGY, compared with summer demand of 1.3 BGY at $0.73 per gallon. As discussed in Section 5.2, as MTBE is reduced, more C4s become available. Because of high vapor pressure, C4s can be blended into winter gasoline but not into summer gasoline. In the summer, the primary substitute for MTBE is ethanol. However, in the winter there are two substitutes for MTBE: C4s and ethanol. As previously noted, a reduction of MTBE may not have an equivalent increase in ethanol demand in the wintertime.

With a sufficiently low refiner value, ethanol should be preferred over C4s in winter, and one would expect winter demand for ethanol to be higher than summer demand. However, Fig. 13 shows that demand for ethanol is lower in the winter than in the summer, even at low ethanol values. Among the factors that explain the seasonal differences in ethanol demand is the low sulfur requirement for gasoline. Sulfur reduction and octane numbers are more costly in the summer, and less costly in the winter. Among other factors, winter blending takes advantage of significant butane blending to maintain octane and control sulfur. Fig. 14 shows how the relative seasonal demands change if there is no requirement for low sulfur gasoline. Compared to Fig. 13, the differences in seasonal demand have been greatly reduced, with reversed seasonal importance in some parts of the demand curves.

Fig. 13. Ethanol demand with MTBE ban in PADD II gasoline production
Year 2006 - 30 ppm sulfur in gasoline



5.9 PADD II, ANNUAL WITH MTBE BAN

It is assumed that the summer season is 5.5 months long and the winter season is 6.5 months long. With due consideration for different season lengths and different gasoline production within seasons, Fig. 15 shows the annualized demand for ethanol used in PADD II gasoline production in year 2006 with an MTBE ban. CG is the greater source of demand for ethanol at values below \$0.75 per gallon and above \$1.02 per gallon. In the \$0.75 to \$1.02 per gallon range, RFG is the source of greater demand for ethanol. At an ethanol value of \$0.35 per gallon, with gasolines containing the maximum

Fig. 14. Seasonal ethanol demand with MTBE ban in PADD II gasoline production
Year 2006 - no low sulfur requirement for gasoline

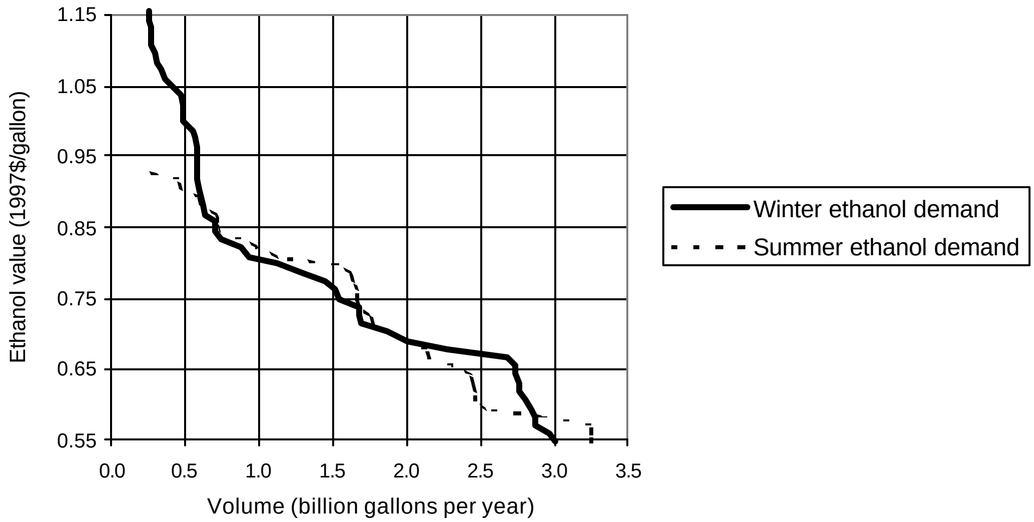
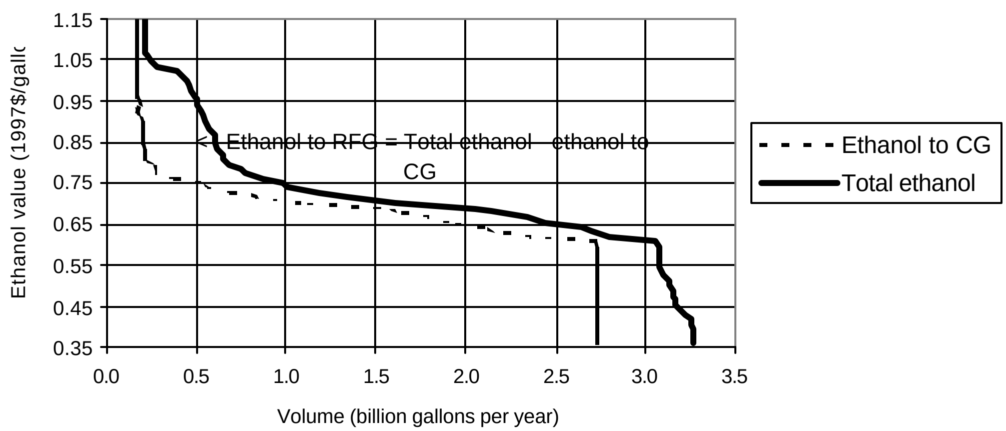


Fig. 15. Annual ethanol demand with MTBE ban in PADD II gasoline production
Year 2006 - 30 ppm sulfur in gasoline



allowable 10 vol percent of ethanol, RFG accounts for 17 percent of total ethanol demand in gasoline blending. The disaggregation of demand in Fig. 15 will be useful in mapping ethanol production into ethanol demand regions, characterized on the basis of ozone non-attainment.

6. CONCLUSIONS

Ethanol competes with MTBE to satisfy oxygen, octane, and volume requirements of certain gasolines. However, the water quality problems caused by MTBE appear to have expanded the market opportunities for ethanol. The use of MTBE in the RFG program has resulted in growing detections of MTBE in drinking water, with between 5 percent and 10 percent of community drinking water supplies in high oxygenate use areas showing at least detectable amounts of MTBE. There have been important debates about the air quality benefits and water quality problems of MTBE. In November, 1998, the U.S. EPA Administrator appointed a Blue Ribbon Panel to investigate the air quality benefits and water quality concerns associated with oxygenates in gasoline, and to provide advice and recommendations on ways to maintain air quality while protecting water quality. Given the Panel recommendations, the EPA Administrator announced that "We must begin to significantly reduce the use of MTBE in gasoline as quickly as possible without sacrificing the gains we've made in achieving cleaner air."

Reduction or elimination of the use of MTBE would increase the costs of gasoline production and possibly reduce the gasoline output of U.S. refineries. MTBE is the dominant oxygenate in RFG, and gasoline production has evolved to depend on the attractive octane and volatility characteristics of MTBE. DOE has reported that elimination of MTBE is equivalent to a loss of up to 5 percent of the U.S. gasoline supply.

The potential gasoline supply problems of an MTBE ban could be mitigated by allowing a modest 3 vol percent maximum MTBE in all gasoline. Compared to a ban, the 3 vol percent MTBE option results in costs that are 40 percent less than an MTBE ban in PADD I+III. Major contributors to costs for a ban of MTBE are control of octane, volatility, and prevention of TAP backsliding.

The winter demand for ethanol may not be as high as expected with a reduction of MTBE use. Absent conversion of MTBE plants to production technologies that utilize isobutylene, ethanol is the primary substitute for MTBE in the summer. However, in the winter, ethanol may have to compete with directly-blended C4s.

In a region with already high use of ethanol, an MTBE ban might have minimal effect on the ethanol demand curve, unless gasoline producers in other regions bid away the local supply of ethanol. PADD II has the highest regional use of ethanol, which provides at least 90 percent of the total oxygenate volume now blended to gasoline in PADD II. Furthermore, the production share of RFG in PADD II is relatively low. Consequently, a reduction in MTBE does not substantially change ethanol demand in PADD II. An MTBE ban in PADD II results in a cost increase of only 0.3 cents per gallon of RFG.

The ethanol/MTBE issue gained momentum in March 2000 when the Clinton Administration released a "legislative framework to encourage immediate Congressional action to reduce or eliminate MTBE and promote renewable fuels like ethanol. The legislative framework being sent to Congress includes the following three recommendations, which taken together as a single package, provide an environmentally sound and cost effective approach: First, Congress should amend the Clean Air Act to provide the authority to significantly reduce or eliminate the use of MTBE. This step is necessary to protect America's drinking water supplies. Second, as MTBE use is reduced or eliminated, Congress must ensure that air quality gains are not diminished. The Clinton-Gore Administration is deeply committed to providing Americans with clean air and clean water. Third, Congress should replace the existing oxygenate requirement in the Clean Air Act with a renewable fuel standard for all gasoline. By preserving and promoting continued growth in renewable fuels, particularly ethanol, this step will increase farm income, create jobs in rural America, improve our energy security, and help protect the environment (U.S. EPA, 2000)."

While the case studies described in this report were performed prior to March 2000, the study premises are consistent with the Administration announcement, and the ethanol demand curve estimates of this study can be used to evaluate the impact of the Administration principles and related policy initiatives.

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