

**Comment on**

**RFG/MTBE  
Issues and Options  
in the Northeast**

**May 11, 1999**

**Submitted to**

**Northeast States for Coordinated  
Air Use Management  
(NESCAUM)  
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## Introduction

In April 1999, the Northeast States for Coordinated Air Use Management (NESCAUM) released a draft summary entitled “RFG/MTBE Issues and Option in the Northeast” as well as a related paper entitled “An Assessment of Options for Reducing MTBE in Reformulated Gasoline”.

The draft summary covers various unintended adverse consequences associated with the increased use of methyl tertiary butyl ether (MTBE) in the reformulated gasoline (RFG) program. Current concerns focus primarily on the increasing presence of MTBE in drinking water.

In response to these concerns, the NESCAUM draft summery explores four fuel program options as follows:

- Option 1 - Status quo
- Option 2 - Federal RFG with alternative oxygenates
- Option 3A - State Clean Gasoline Program (w/Federal RFG performance standards - revised oxygen requirements)
- Option 3B - State Clean Gasoline Program (w/fuel parameter specifications)
- Option 4 - No clean fuel strategy

Among the above, Option 2 and possibly some variations of Option 3A would result in the increased use of ethanol as a fuel oxygenate. Increased demand for ethanol to replace MTBE gives rise to questions about the supply and demand for ethanol.

In addition, MTBE is typically blended at the refinery and already present in the gasoline when it arrives at the terminal. Ethanol, however, would be shipped to the terminal and added to the gasoline at the truck loading rack. Consequently shipping and storage capabilities must also be considered.

Our comments are limited to the supply/demand and logistic issues should ethanol demand in the Northeast states be increased through a ban or other mechanism eliminating or reducing the use of MTBE. Please note that we take no position on such a ban. Considerations of such issues include public health and water quality issues that go beyond our area of expertise. Our intent here is simply to

provide information on how much ethanol would be available and how it would be transported to and stored in the Northeast market.

### Ethanol Demand

On a volume basis, ethanol contains more oxygen than MTBE and consequently takes less volume to meet the oxygen requirement for RFG. A 2.0 wt% oxygen level can be achieved by blending 5.7 v% denatured ethanol. Table #1 lists the RFG volumes for the subject areas and the corresponding ethanol demand at 5.7 v% of the total.

**Table 1 - Ethanol Demand for Northeast RFG Areas**

Non-Attainment Area	Gasoline (000s gal.)	Ethanol Demand (000s gal.)
Hartford CT	971,386	55,369
New York/No. New Jersey	6,676,592	380,566
New Hampshire (Manchester)	303,814	17,317
Massachusetts (Boston +)	2,720,116	155,047
Rhode Island (entire state)	568,066	32,380
New York (outside NYC)	184,362	10,509
Connecticut (rest of state)	43,775	2,495
New Jersey (Atlantic City)	402,702	22,954
<b>Total</b>	<b>11,870,813</b>	<b>676,636</b>

**Bold indicates required areas**

State considered Northeast by EPA are CT, NH, NJ, NY, ME, MA, RI, VT

SOURCE: USEPA

Based on the EPA projections in Table 1, it would take 676,636,000,000 gallons of ethanol per year to meet the RFG/oxygen demand for the Northeast states. The number compares very closely to the 684 million gallon ethanol demand cited by NESCAUM<sup>(1)</sup>.

The remainder of our comment is based on an ethanol demand of 680,000,000 gallons annually for the Northeast RFG program.

### **Ethanol Supply**

Appendix A-1 lists ethanol plants that were in production at the end of 1998. Appendix A-2 lists plants that have started production since the end of 1998 or that will start production in 1999. In addition to U.S. production about 50 million gallons of ethanol will be imported from countries covered under the Caribbean Basin Initiative (CBI). Total ethanol production in 1998 was 1,394,400,000 gallons leaving an excess of ethanol supply available. These figures are recapped in Table 2.

1999 Ethanol production capability	1,838,800,000
1998 Production rate	1,394,400,000
<hr/>	<hr/>
Underutilized capacity	444,400,000
Imports	50,000,000
<hr/>	<hr/>
Excess ethanol supply	494,400,000

Currently 650,000,000 gallons of ethanol per year are used to comply with the oxygen standard in RFG and Oxyfuel programs<sup>(2)</sup>. From this it can be estimated that 744,400,000 gallons of remaining production in 1998 were used in the octane enhancement market. As demonstrated in Table 3, excess capacity could cover a large portion of the demand but there would still be a need for an additional 185,600,000 gallons of ethanol. It would be necessary to bid this away from the midwest markets where ethanol is typically used for octane enhancement.

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(1) *An Assessment of Option for Reducing MTBE in Reformulated Gasoline (page 9)*

(2) *Source: Estimated by Renewable Fuels Association*

**Table 3 - Ethanol Supply**

Northeast States Ethanol Demand	680,000,000
Current Excess Capacity/Supply	494,400,000
Balance	(185,600,000)

Although it is not our intent here to make detailed cost estimates on available ethanol supply, we do think it appropriate to discuss the costs likely associated with bidding ethanol away from the lower valued octane enhancement markets. A discussion of such considerations is contained in Appendix B.

**Table 4 - Ethanol Supply**

Current Excess Capacity	494,400,000
Ethanol for Octane Market	744,400,000
Total	1,238,800,000

In any event, ethanol supply for the Northeast would come from a combination of excess production capacity and redirection of product from the lower valued octane market which collectively represents 1,238,800,000 gallons. This exceeds Northeast demand by 558,800,000.

The above referenced excess demand does not consider the impacts of other areas simultaneously adopting programs that would increase demand for ethanol. For instance California, Governor Gray Davis, by recent executive order, has ordered the California Environmental Protection Agency and Air Resources Board to “devise and carry out a plan to begin immediate phase out of MTBE from California gasoline, with 100% removal achieved no later than December 31, 2002.” A time table for removal of MTBE from gasoline is due by July 1, 1999.

Total ethanol demand to meet the minimum oxygen standard for Federal RFG areas in California is projected to create a demand for approximately 550,000,000 gallons of ethanol<sup>(1)</sup>. Combined de-

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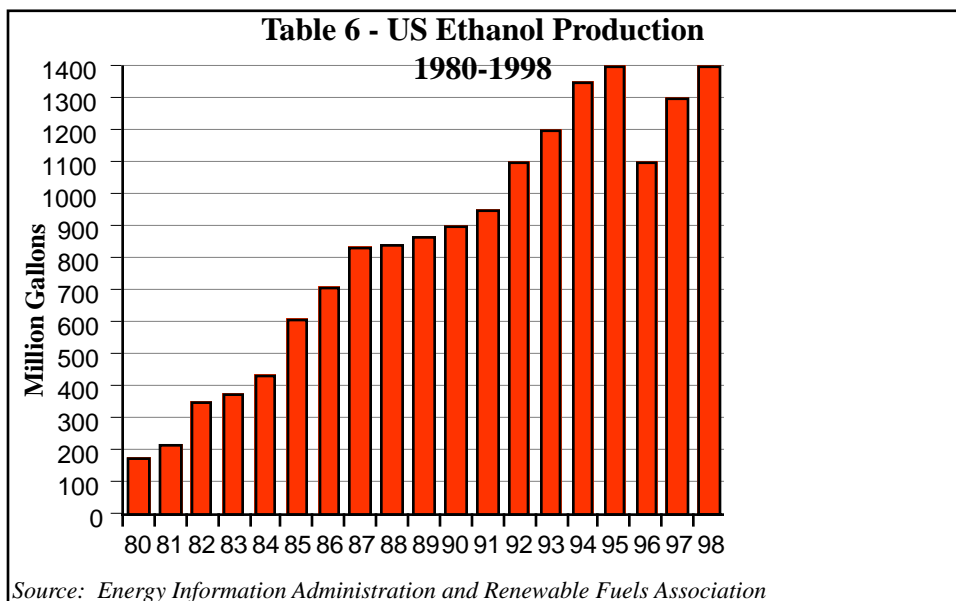
(1) *The Use of Ethanol in California Clean Burning Gasoline-Ethanol Supply/Demand and Logistics, Downstream Alternatives Inc., February 1999*

mand for the Northeast states and California RFG will approach 1,230,000,000. This is equivalent to the combined ethanol volume available from underutilized capacity and the octane markets. However California will not ban MTBE outright but rather phase in the ban. It is likely that any reduction in MTBE in the Northeast States would employ a similar approach. While such MTBE phase out scenarios have not been determined, one frequently discussed approach is to reduce MTBE usage by 25% a year until totally eliminated.

Table 5 presents the increase in demand if such a program were phased in over a four year period In both California and the Northeast. In calendar year 2000 increased demand does not even equal underutilized production. In calendar year 2001 demand equals 615,000,000 gallons which would require bidding a small portion of product away from the octane markets. In 2002 ethanol demand would increase to 922,500,000 gallons which would necessitate using slightly in excess of half the ethanol from the octane enhancer market.

<b>Calendar Year</b>	<b>MTBE Reduction</b>	<b>Resulting California Demand</b>	<b>Resulting Northeast Ethanol Demand</b>	<b>Total Ethanol Demand</b>
2000	25%	137,500,000	170,000,000	307,500,000
2001	50%	275,000,000	340,000,000	615,000,000
2002	75%	412,500,000	510,000,000	922,500,000
2003	100%	550,000,000	680,000,000	1,230,000,000

So ethanol supply does not really become tight until 2003 in this scenario. However there will be other sources of supply by that time, The ethanol industry has always increased capacity to meet new demand opportunities, as depicted in Table 6.



If a commitment is made to increase the use of ethanol, production capacity would be increased to meet that demand. Several companies producing ethanol today have investment capital of

their own which could be used to finance production expansions. Industry sources indicate that such expansion would add another 600 million gallons of ethanol production capacity within 12 to 18 months<sup>(1)</sup>. Ethanol production facilities are largely modular and expansion at existing plants can be done very quickly simply by adding new equipment to existing production systems. “Ground up” plants have also been completed in 18-24 months from time of ground breaking.

Initially expansion would come from the corn based ethanol industry since expansion would be in existing plants. However biomass based production is nearing commercial reality. The Northeast states have feedstock sources for biomass based production and it is likely that some production capacity based on biomass feedstock would eventually be built in the Northeast. In fact, the Renewable Fuels Association has been in contact with two companies currently exploring the possibility of building plants in the Northeast area.

It should also be noted that as we approach the 2003 time frame some CO non-attainment areas may achieve attainment status thereby reducing ethanol demand for these programs.

(1) Jack Huggins, Vice President, Ethanol Operations, Williams Energy Service, before EPA’s Blue Ribbon Panel to Review the Use of Oxygenates in Gasoline, April 29, 1999

**Transportation of Ethanol to Northeast States**

Ethanol is not shipped by pipeline due to operational considerations. Moreover, pipelines do not run from the ethanol plants in the Midwest to the Northeast states or other major markets. Consequently, ethanol is normally shipped by transport truck, rail, or barge/ship. Distances to the Northeast states render transport cargoes uneconomical. Consequently ethanol would be shipped by rail and barge. A number of industry analysts have incorrectly assumed that nearly all ethanol would be shipped by rail. This is simply not true. Nearly every terminal in the Northeast states RFG areas is accessible by water, far more than is accessible by rail. It is far more likely that at least 70% of product would be moved by barge. This would entail shipment from Midwest plants down the Mississippi river for staging in New Orleans, and then barge shipments to the applicable markets/terminals.

Assuming a 70% barge/30% rail split and annual demand of 680,000,000 gallons of ethanol for the Northeast, the transportation demands would be as listed in Table 7.

<b>Table 7 - Transportation Demands</b>		
<b><u>Annual Total Ethanol Demand</u></b>	<b><u>70% Barge</u></b>	<b><u>30% Rail</u></b>
680,000,000 gallons	476,000,000 gallons	204,000,000 gallons
	1133 Annual barges	7034 Annual railcar movements
	94 Monthly barges	586 Monthly rail car movements

In the grand scheme of total rail car and barge movements, these are reasonably insignificant volumes. In addition this represents total movements after a four year phase in. The transportation industry would have more than enough time to adjust to these needs.

Rail cars would likely be shipped to some terminals for direct distribution from those terminals (i.e. blends). Terminals receiving barge quantities would not only blend and distribute ethanol blends but would also serve as distribution points to ship transport load quantities of ethanol to smaller terminals or terminals without water or rail access.

## **Ethanol Storage and Distribution**

Terminals vary widely in their degree of flexibility to handle new or additional products. Ethanol would represent such a product due to its special handling characteristics and delivery methods. To determine the viability of widespread distribution of ethanol in the Northeast would require a reasonably detailed assessment of product terminals where ethanol would be blended with gasoline for final distribution to the retail outlet or other final destination. Likewise, it is necessary to identify terminals which could serve as a central ethanol redistribution point, receiving rail or marine cargos, storing product and providing outbound truck delivery to outlying terminals.

Because ethanol absorbs moisture it is almost always blended at the final destination terminal. This is usually accomplished in one of three ways.

**Tank Blending:** Ethanol and gasoline (in this case RBOB) could be blended in one or more terminal tanks. A few terminals in the Midwest, especially those with recirculation capability (in-tank devices to recirculate/stir the product) have distributed ethanol blends in this manner. However this method is the least preferred of the methods available due to the potential for the blend to encounter excessive moisture which could result in the ethanol phase separating from the blend. Additionally terminal tankage is not routinely equipped with recirculation/mixing devices.

**Top-off Blending:** In this scenario, ethanol and gasoline are injected separately into the transport truck with the agitation from loading and transport accomplishing the blending process. Volumes are controlled by preset meters activated by loading cards. This could be done within a single terminal (i.e. one loading rack) or by loading the ethanol at one terminal and the gasoline at another terminal (both terminals in the same proximity). This method was successfully used throughout the Midwest for a number of years and is still utilized at some terminals although in-line/injection blending is now the more common method.

In a developed market, in-line/injection blending is preferred because of the greater control and less potential for blending errors. However in a newly established or developing market, top-off blend-

ing actually offers certain advantages. Primary among these is more rapid conversion time frames via cross utilization of terminals. It is not likely that every terminal would have ethanol available in a short time frame. In this case a terminal without ethanol could still load out gasoline that could be top-off blended with ethanol at a nearby terminal. Terminals are, of course, usually located adjacent to or near other terminals.

By utilizing top-off blending, terminals without ethanol could meet the oxygen requirement by utilizing ethanol available at other terminals. When this is done there is usually a "stop charge" for the transport to make the additional stop. This usually equates to \$0.003 to \$0.005 per gallon of finished product.

**In-line/Injection Blending:** The preferred method for an established or mature ethanol blend market is in-line or injection blending. In this case, the ethanol and gasoline (in this case RBOB) are blended in-stream prior to the meter and a single finished product is metered .

This method eliminates potential for blending errors and provides better quality control. Additionally, it provides greater reporting ease for program compliance. This is typically the preferred blending method but as discussed above it is neither necessary nor, in the case of a developing market, in every case desirable.

**Other Modifications:** Some terminals will need to make modifications to offer ethanol even if tankage is adequate. Such modifications may include addition of a floating internal cover to the storage tank, repiping to the loading rack, meters, additional loading arms, and if applicable in-line blending equipment. Such alterations can be made with "off-the-shelf" equipment and typically do not require an extensive permitting process. Injection blenders can be purchased as prefabricated "skid mounted" units that are delivered ready to go except for necessary piping connections. Recent estimates by the California Energy Commission indicate that such modifications would increase the average cost of ethanol blends by 0.1 cents per gallon even including modifying or building segregated storage tanks.

For this comment we compiled a preliminary listing of the number of terminals and means of receipt of product for the Northeast states. Using the OPIS Petroleum Terminal Encyclopedia (1999-

10th edition), we compiled a list of the terminals that serve the Northeast RFG markets. Terminals which did not handle gasoline were eliminated leaving a total of 119 terminals. The degree of information listed in the Petroleum Terminal Encyclopedia varies based on the extent of details provided by the terminal operator. We were however able to determine the following: Only 13 terminals listed rail accessibility while 85 were listed as water accessible (i.e. capable of receiving barges or larger vessels). There were a few terminals that did not indicate accessibility by any mode other than pipeline accessibility and truck. In such cases ethanol would need to be delivered by transport truck. A copy of the list of Northeast Terminals is included in Appendix C.

Most terminals in the Northeast are fairly large due to the fact that they take barge quantity (or larger) shipments, In fact of the terminals listed in Appendix C, 36 have storage capacity in excess of a half million barrels and only 22 indicate they have less than 200,000 barrels of storage, Larger terminals usually have several tanks affording them greater flexibility to reassign tankage due to new needs, pipeline policy changes, changes in demand, and other factors that affect tankage assignment.

It is likely that a majority of terminals will be able to reassign tankage for ethanol storage although some minor modifications to the tank may be necessary. However smaller terminals may find it necessary to either add tankage or have transports pick ethanol up at an adjacent terminal.

A greater challenge for these terminals would be any phase in program that required them to carry all grades of both MTBE based RFG and RBOB (see next section).

### **Base Gasoline/RBOB**

One of the reasons that RFG markets tend to use predominately ethanol or predominantly MTBE is the limitation of terminals to store both RFG containing MTBE and an RBOB for ethanol blending. While it is likely that many terminals can reassign tankage for ethanol storage, add the small amount of tankage necessary, or even pick up ethanol at an adjacent terminal, it is doubtful many would have adequate space for both RFG containing MTBE and the RBOB necessary for ethanol blending.

Another consideration is pipeline shipments, both frequency and size. Since RFG containing MTBE is the predominant fuel in the Northeast states, timing and size of pipeline shipments do not present any problems. However the predominance of MTBE blends does make it difficult to ship

RBOB since its volume is rather small. Any plans to reduce the use of MTBE and increase the use of ethanol must take these factors into consideration.

For instance, a 25% per year phase down could not be applied by terminal because many terminals couldn't carry both fuels. On a company basis some companies who are multiple terminal operators could possibly achieve targets by carrying MTBE type fuel at one or more terminals and RBOB for ethanol blending at other terminals. However for the single terminal operator it is more likely that they would carry one fuel or the other.

Given enough cooperation between companies, many of these issues could be addressed through exchange agreements. For instance, company A, B, and C might carry MTBE based RFG. Company D could carry RBOB and ethanol. By utilizing exchange agreements A, B, and C could distribute ethanol based RFG from company D while company D could take back their exchange barrels of MTBE based RFG from the other three companies. In this manner each company could distribute both types of fuel while terminaling only one or the other. There would likely be an exchange differential paid from the companies taking ethanol blends in exchange for MTBE blends. This differential would reflect any cost increase for manufacturing the RBOB for ethanol blends. These exchange agreements could be done on a single grade basis or all three grades depending on terminal size and volumes involved. Exchange agreements are routinely used throughout the petroleum industry to address various logistic issues.

Some alternatives that could be considered to address a phase-in type program are as follows:

1. **Phase In Targets by Grade:** This option could be encouraged among refiners. In this situation a refiner could convert only one grade (i.e. regular, midgrade, or premium) at a time so that the number of actual grades stored is not increased. This combined with cross utilization of terminals and exchange agreements might provide the greatest degree of flexibility with least amount of regulatory oversight.
2. **Geographic Phase In Targets:** With this option certain markets would be phased in over a given time frame. Considerations would have to be given to the servicing terminals since some termi-

nals may serve more than one area. However as an example, all smaller markets (i.e. New Hampshire, Rhode Island, Connecticut, Atlantic City and Hartford) could be phased in during 2000, followed by Boston and New York in 2001 and/or 2002. This would also eliminate the need to carry two types of fuel and minimize the need for regulatory oversight.

3. **MTBE Reduction Credits:** With this option some mechanism could be established to trade credits for reducing use of MTBE. Some refiners could sell less MTBE than the phase out target and sell credits for the excess to refiners who fall short of the target. This type of approach was used in eliminating lead and though it minimizes market impacts it requires a higher degree of regulatory oversight. Furthermore it requires some type of penalty or assessment should refiners fall short of targets and credits be insufficient. Any such penalty must be high enough to offset any economic benefits of not meeting prescribed targets. Lastly, it is uncertain what the legal implications are for states choosing such an approach and this would need to be considered

All three of the above approaches also address important competitive factors. While there is a great deal of disagreement about how much more it would cost to make RFG containing ethanol (due to the need for a lower volatility base fuel), everyone would concede that it will at least cost more.

Options 1 and 2 address this by requiring a phase in by grade in the case of option one or geographically in the case of option two. Option 3 addresses this competitive factor because those refiners who do not reduce MTBE use by the targeted amounts would have to buy credits from those who do. The market value of such credits could, and likely would, reflect the increased cost of the lower volatility base fuel if ethanol is the mechanism used to achieve the MTBE reduction targets.

## **Summary**

In order to replace MTBE with ethanol in RFG it is necessary to blend ethanol at 5.7v% to achieve the 2.0 wt% oxygen requirement. Based on this blend level, ethanol demand for Northeast states RFG areas is estimated at 680,000,000 gallons annually. This demand could currently be met with a combi-

nation of currently underutilized ethanol production capacity totaling 494,400,000 and redirection of product from lower valued octane enhancement markets.

Even if California and the Northeast states were to adopt phased in programs simultaneously supply would be adequate for up to 75% of both markets. Additional production capacity of up to 600,000,000 gallons could be brought on line in as little as 12-18 months by increasing capacity at existing plants. Even ground up plants have recently been brought on line in 18-24 months (groundbreaking to production).

The majority of ethanol would be moved to the Northeast via barge. Consequently there would be no great strain on the railway system. A large majority of terminals in the subject area can take water-borne cargo.

While ethanol supply and its transportation to the Northeast markets are not impediments to its expended use, any phase in schedule must allow for the fact that while some terminals could be prepared to distribute ethanol on very short notice, others may need several months to prepare their facilities especially smaller terminals with limited storage.

Any phase in plan must be designed to address the fact that many terminals cannot handle two types of RFG (i.e. MTBE blends and RBOB) for all grades. Consequently when considering phase in programs, novel approaches such as phase in by grade or geographic area or utilization of trading credits should be considered.

If a determination is made that MTBE use should be reduced or eliminated and that ethanol should fill that void, a program to successfully implement its use can certainly be developed. The challenges associated with implementing an ethanol program in the Northeast RFG markets are not insurmountable but do require a degree of planning and preparation.

# **APPENDIX A**

## **Ethanol Supply**

<u>Company</u>	<u>Location</u>	<u>Capacity-MGY</u>
ADM	Decatur, IL Peoria, IL Cedar Rapid, IA Clinton, IA Walhalla, ND Columbus, NE	780     85
Minnesota Corn Processors Marshall, MN		35
Williams Energy Services Cargill Eddyville, IA	Pekin, IL Blair, NE	100 100
New Energy Corp. Midwest Grain Atchison, KS	South Bend, IN Pekin, IL	85 78 30
A.E. Staley High Plains Corp. Colwich, KS	Loudon, TN York, NE	42 40 20
Portales, NM Chief Ethanol AGP		15 40 30
Nebraska Energy Chippewa Valley Ethanol Corn Plus Al-Corn	Aurora, NE Benson, MN Winnebago, MN Claremont, MN	30 17 15 15
Ethanol 2000 Agri-Energy Minnesota Energy Alchem	Bingham Lake, MN Luverne, MN Buffalo Lake, MN Grafton, ND	15 15 11 10
Heartland Corn Products Grain Processing Corp. Reeve Agri-Energy Pro-Corn	Winthrop, MN Muscatine, IA Garden City, KS Preston, MN	10 10 10 10
Heartland Grain Fuel Morris Ag Energy Georgia-Pacific Broin Enterprises Mandildra Ethanol Parallel Products Cucamonga, CA	Aberdeen, SD Morris, MN Bellingham, WA Scotland, SD Hamburg, IA Louisville, KY	8 8 7 7 7 7 3
Wyoming Ethanol J.R. Simplot Burley, ID Golden Cheese Merrick/Coors Kraft Inc. Minnesota Clean Fuels Jonton Alcohol ESE Alcohol Pabst Brewing Vienna Correctional	Torrington, WY Caldweel, ID  Corona, CA Golden, CO Melrose, MN Dundas, MN Edinburg, TX Leoti, KS Olympia, WA Vienna, IL	4 3 3 1.5 1.5 1.3 1.2 1.1 0.7 0.5
TOTAL		1715.8
(mg)		million gallons per year

Source: Bryan & Bryan Inc. and the Renewable Fuels Association

**U.S. Ethanol Plants - Under Construction**

**A-2**

<u>Company</u>	<u>Location</u>	<u>MGY</u>
Exol Corporation	Albert Lea, MN	30
Atkins Energy	Lena, IL	30
BC International	Jennings, LA	20
Nebraska Nutrients	Sutherland, NE	15
Central Minnesota	Little Falls, MN	15
Heartland grain Fuels	Huron, SD	8
Sunrise Ethanol	Blairstown, IA	5
<b>Total</b>		<b>123</b>

**million gallons per year (mgy)**

*Source: Bryan & Bryan Inc. and the Renewable Fuels Association*

**U.S. Ethanol Plants - Engineering/Planning Stage**

<u>Company</u>	<u>Location</u>	<u>MGY</u>
American Agri-Technology	Great Falls MT	30
CORN-er Stone Farmers Coop	Luverne MN	15
RDO	Rapid Park MN	15
Dawson Project	Dawson MN	20
Renewable Oxygenates Inc.	Madison MN	15
EMEC	Preston MN	10
Arkenol	Sacramento CA	12
Quincey Library Group	CA	20
Gridley Project	CA	12
<b>Total</b>		<b>149</b>

*Source: Supply and Cost of Alternatives to MTBE in Gasoline, Technical Appendices-Report on the Oxygenate Market: Current Production Capacity, Future Supply Prospects and Costs Estimates, California Energy Commission, October 1998*

## **APPENDIX B**

### **Economics to Redirect Ethanol from the Midwest Octane Market to Northeast RFG Markets**

## **Economics to Redirect Ethanol from the Midwest Octane Market to Northeast RFG Markets**

A detailed cost analysis is beyond the scope of this comment. However since some ethanol supply for Northeast States would be redirected from lower valued uses, we felt a discussion of those cost aspects was warranted.

Ethanol has traditionally been priced on the basis of margin improvement, octane value, or oxygenate value. In the early years of ethanol use, i.e. 1980s, ethanol was sold largely by pricing it in a fashion that, net of tax credits, it was slightly cheaper than gasoline allowing blenders to lower their total product cost. As state tax credits diminished and ethanol began to achieve more widespread acceptability, it began to be priced more for its octane value. This involves two approaches. In some cases a refinery might make a sub-octane gasoline so that, when blended with ethanol at the terminal it would meet the required octane specification. The second and more common method is to add ethanol to unleaded regular, selling the resulting blend as mid-grade, and/or blending unleaded regular with a small amount of premium and ethanol to achieve the octane requirement of a premium grade product. More recently a large portion of ethanol produced has been sold for its value as an oxygenate to comply with the oxygen requirements of oxygenated fuel and reformulated gasoline programs.

The Renewable Fuels Association estimates that in 1998 approximately 650,000,000 gallons of ethanol was used to meet oxygen standards. Based on 1998 production figures this would indicate that about 740,000,000+ gallons was sold into the octane market. Today's low gasoline prices and the absence of state tax credits preclude the use of ethanol solely as a product extender/margin improver.

Ethanol supply available for any Northeast States program would come initially from production increases in underutilized production, new plant production, and by redirecting products from the lower valued octane market. While ethanol is priced based on its octane and/or oxygenate values, its production costs are dictated by the unrelated price of corn. Production costs do not have a major impact on pricing decisions since product must be priced to compete based on its value to the end user. Production costs do however have an impact on production volume. Large well financed plants can alter their production to market conditions and often have contractual agreements for pricing and volume.

Smaller plants will typically operate as long as their net plant price exceeds production costs. Although this typically results in selling at a price that is below total operating costs inclusive of debt service and amortization, it does at least allow some payment toward debt service. Once sales prices fall to a level that does not allow a gross margin above production costs, smaller plants will typically shut down temporarily.

The majority of ethanol sold into current oxygenate markets is supplied by large producers with some product supplemented by smaller plants. A large portion of this product is sold based on contracts or long term commitments. Consequently plants starting production in 1999 will find themselves initially relegated to the octane enhancer market and would need to price their product accordingly.

Ethanol for Northeast States, whether from new plants or existing production, would come from the octane enhancement market since that represents the current lowest price use of fuel grade ethanol. The octane market can be divided into two distinct groups, those states with state tax credits and those without. Product sold in states with tax credits sells at a higher price due to the blenders ability to recoup higher costs through the tax credit. There are only a few states with tax credits remaining and those are recapped below in Table # B-1.

**Table #B-1 - States with Tax Credits for Ethanol**

	<u>Cents per gallon</u>	<u>percent</u>	
Alaska	\$ .06		
Connecticut	\$ .01		
Hawaii		4%	
Idaho	\$ .025		
Illinois		2%	(sunset 2003)
Iowa	\$ .01		(sunset 2007)
South Dakota	\$ .02		

*Source: The Energy Independent, Bryan & Bryan Inc., June/July 1998*

The states listed in the table provide credits or exemptions from the gasoline pump tax (state motor fuels tax) or sales tax and are available to the blender. A few other states offer producer credits to the production facility but there is no requirement for these plants to sell their product in state.

From the above table and preceding discussion we can see that it would not likely be economically feasible to supply Northeast States' ethanol from certain higher valued markets. The estimated 650,000,000 gallons sold into the oxygenate market makes up the first block of such product. Although there are no mandates that ethanol be used in these markets, historical use indicates it is the oxygenate of choice in certain markets. Within the octane enhancer market it is necessary to first look at state tax credits and/or exemptions.

**Alaska:** Ethanol sales in Alaska are primarily to meet the requirement of the winter time oxygenated fuels program requirement for Anchorage. This volume would be included in the RFA estimate. In any event gasoline sold in Alaska and corresponding ethanol needs are very small.

**Connecticut:** Any ethanol sold in the state would be largely for meeting oxygen requirements and would be included in the RFA estimate. In any event Connecticut is part of the group of states assessed here.

**Hawaii:** Ethanol is not currently blended in Hawaii.

**Idaho:** To draw product from this state to the Northeast market would require an additional \$.25 per gallon compared to a state with no credit.

**Illinois:** A large portion of ethanol sold in Illinois is to meet the oxygen requirement in the Chicago market and would be included in the RFA estimate for program use. However ethanol is sold outside the Chicago market for octane value. In the later case it would take a price approaching \$.15 per gallon higher to draw product from this market, compared to a state with no credit.

**Iowa:** Ethanol used in Iowa is strictly for octane enhancement. To draw product from this market would take a price approximately \$.10 per gallon higher than a state with no credit.

**South Dakota:** Ethanol sold in South Dakota is sold into the octane enhancer market. It will take \$.15 to \$.20 per gallon more to draw product from this state compared to one with no credit. Gasoline volume in South Dakota is relatively low as is corresponding ethanol demand.

From the above states, only Idaho, Iowa, and South Dakota and a portion of Illinois present higher priced markets within the octane market segment. Consequently ethanol from the octane enhancement market would be redirected from other states, primarily in the Midwest.

The Northeast States would be similar to other markets where ethanol is priced primarily for its value as an oxygenate. This is turn would be driven by the price of gasoline since in the case of an elimination of MTBE from the market place, ethanol prices would be keyed off of gasoline prices absent a competing oxygenate with significant market presence. These prices would be set based on the value of product in applicable destination states and transportation costs would not figure into the pricing equation because price would be based on value to the blender. However ethanol producers would consider transportation costs when determining whether or not to meet the necessary market price.

The cost of shipping ethanol to the Northeast market will fall in a range of 10-12 cents per gallon of ethanol. In addition use of a central breakout terminal will result in handling charges of 25-70 cents per barrel (\$0.006 to \$0.017 per gallon) depending on the type of storage/throughput agreement and volumes involved. In some cases there will also be the cost of transporting the ethanol from the central breakout terminal to the destination terminal and a throughout charge at the destination terminal (in the case of third party terminals and throughput agreements). However these later charges are experienced in all other markets and are not particularly relevant. Compared to the Midwest octane market, transportation and handling costs will range from \$0.106 to \$0.137 per gallon of ethanol. Ethanol producers would need to recoup this amount plus some premium to the Midwest octane market to induce them to supply ethanol to Northeast.

Given the uncertainty of projecting gasoline prices, it becomes equally as difficult to project ethanol prices. However it is not difficult to predict the minimum price premium required to draw ethanol from the Midwest octane market to the Northeast market. Producers would anxiously redirect production for as little as \$0.05 incremental margin per gallon of ethanol providing it were for a market involving long term commitments. Consequently ethanol could be drawn from the Midwest market for this margin improvement plus transportation, or in other words for as little as \$0.156 to \$0.187 per gallon of ethanol.

To get some idea of what type of prices this might lead to, it is necessary to look at historic gasoline prices in some of the Midwest markets from where Northeast ethanol supplies would need to be drawn. Again these are the lowest valued markets, i.e. octane enhancement markets without state tax credits. We have chosen Michigan, Indiana, and Ohio as representative markets within this group. Table #B-2 lists the average rack prices for unleaded for each of these terminals for the period of July 1, 1997 through June 30, 1998.

**Table #B-2 - Annual Average Gasoline Rack Price  
 (time frame 7-1-97 to 6-30-98 - average of all suppliers)**

Terminal location	87 octane unleaded
Indianapolis IN	.6040
Columbus OH	.5735
Detroit MI	.5813

*Source: OPIS Historical Yearly Rack Average by Supplier*

The ethanol octane blend market in the Midwest has traditionally been priced at the rack price of unleaded plus 54 cents per gallon (the value of the federal motor fuels excise tax credit). Prices would be higher in states with state tax credits but this is not relevant here since it is states without credits from which product would be redirected. While the formula of unleaded plus 54¢pg somewhat under-values the octane value of ethanol, it is the traditional pricing mechanism and the one currently used.

**Table #B-3 - Ethanol Pricing Calculation**

Midwest 3 market average unleaded rack price (from Table B-2)	.5863
Value of federal credit	.5400
Resulting Rack Price	\$1.1263
Less Transportation/Distribution Costs	.0400
Projected Resulting Plant Net Back Price	\$1.0863

Averaging the three markets in Table #B-3 we arrive at an average market price of \$.5863 per gallon of unleaded regular . In order to induce blenders to use ethanol in this fashion, it is necessary to provide a blend margin incentive which has traditionally been provided by the unleaded price plus 54 cents formula. In this case ethanol at the rack would be worth a \$1.1263 per gallon in the Midwest averaged across the indicated time frame. With transportation and distribution costs, price net back to the plant would be approximately \$1.08 - \$1.09 per gallon. Obviously gasoline prices have recently been much lower with prices in the mid 40 cent per gallon range currently not uncommon. Consequently ethanol prices at the rack (which move largely in tandem with gasoline in these markets) have fallen below the \$1.00 per gallon mark in many markets. For projection purposes it would then be safe to assume a near to mid term Midwest ethanol price range(FOB production plant) of \$.95 to \$1.05 per gallon. As mentioned earlier, it would likely take 5 cents per gallon improvement in plant net back prices to result in redirection of this product to the Northeast market. This can provide some idea of the range of prices as listed in Table #B-4.

**Table #B-4 - Projected Price Range - Northeast Market Ethanol**

Ethanol price range (FOB plant)	\$ .950	-	\$ 1.05
Price incentive	.050	-	.050
Transportation/handling costs	.106	-	.137
Projected Northeast price range	\$ 1.106	-	\$ 1.237

It is very unlikely that prices would exceed the upper end of the price range. At any corn price below \$3.00 per bushel, an ethanol price (FOB production facility) of \$1.10 would stimulate increased production from underutilized capacity, new plant start ups, and restarting of idle plants. Consequently it is unlikely that ethanol costs, laid in to Northeast would exceed the \$1.20-\$1.25 range and this would only be in a case where gasoline rack prices in the Midwest recover to a level above \$0.65 per gallon. Prices conditions, as of May 1999, would likely result in Northeast delivered ethanol prices in the \$1.08-\$1.12 range at the current time. Net of the federal tax credit this equates to \$.54-\$.58 per gallon which is extremely competitive with MTBE when ethanols higher oxygen content is considered.

# **APPENDIX C**

## **Northeast Market Terminals**

*Source: OPIS Directories Petroleum Terminal Encyclopedia*

St	Terminal	City	truck	rail	water	capacity	comments
CT	Motiva Enterprises	Bridgeport	x	x	x	n/a	
CT	Motiva Enterprises	East Hartford	x			21,097	
CT	Amerada Hess Corporation	Groton	x		x	n/a	
CT	New Haven Terminal Inc.	New Haven	x	x	x	800,000	
CT	Northeast Petroleum	New Haven	x		x	1,700,000	
CT	Wyatt Inc.	New Haven	x		x	4,200,000	
CT	Amerada Hess Corporation	New Haven	x		x	n/a	
CT	Getty Terminals Corp.	New Haven	x		x	82,678	
CT	Gulf Oil, Limited P.	New Haven	x		x	539,750	
CT	Citgo Petroleum Corp.	Rocky Hill	x			181,000	
CT	Sprauge Energy	Stamford	x		x	57,000	
CT	Amerada Hess Corporation	Wethersfield	x		x	n/a	
MA	Armory Terminals Inc.	Beverly	x			100,000	
MA	Mobil Oil Corp	Boston	x		x	794,500	
MA	Citgo Petroleum Corp.	Braintree	x		x	1,305,417	
MA	Gulf Oil Limited Partnership	Chelsea	x		x	716,000	
MA	Exxon Company	Everett	x		x	n/a	
MA	Shell Oil Company	Fall River			x	560,000	barge/tanker
MA	only						
MA	Global Petroleum Corp	Revere	x		x	820,000	
MA	Coastal Oil New England Inc.	Revere	x	x	x	1,413,000	
MA	Mobil Oil Corp	Springfield	x			277,900	
MA	Tosco Corp	Revere	x		?	850,000	
ME	Mobil Oil Corp	Bangor	x		x	112,400	
ME	Mobil Oil Corp	So. Portland	x		x	722,000	
ME	Motiva Enterprises LLC	So. Portland	x		x	838,503	
ME	Gulf Oil Limited Partnership	So. Portland	x		x	732,952	
ME	Koch Refining & Mrktg	So. Portland	x		x	333,333	
ME	Citgo Petroleum Corp.	So. Portland	x		x	831,093	
ME	Sprauge Energy Corp.	So. Portland	x	x	x	1,404,000	
NJ	IMTT-Bayonne	Bayonne	x	x	x	14,000,000	
NJ	Amerada Hess Corporation	Bayonne	x		x	n/a	
NJ	IMTT-Richmond	Bayonne	x		x	973,000	
NJ	Amerada Hess Corporation	Bogota	x		x	n/a	
NJ	GATX Terminals Corp	Carteret	x	x	x	6,652,000	
NJ	Amoco Oil Company	Carteret	x		x	1,340,000	
NJ	Amerada Hess Corporation	Edgewater	x		x	n/a	
NJ	Koch Fuels Inc.	Gloucester	x		x	780,000	
NJ	Gulf Oil Limited Partnership	Linden	x			568,374	
NJ	Mobil Oil Corp	Linden	x			335,400	
NJ	Tosco Corp	Linden	x			1,560,000	
NJ	Citgo Petroleum Corp.	Linden	x		x	3,588,967	
NJ	Stratus Petroleum	Newark	x		x	1,061,000	
NJ	Getty Terminals Corp	Newark	x		x	233,400	
NJ	Sun Refining & Mrktg Co.	Newark	x		x	581,000	
NJ	Motiva Enterprises LLC	Newark	x		x	1,196,711	
NJ	Amerada Hess Corporation	Newark	x		x	n/a	
NJ	Mobil Oil Corp	Paulsboro	x			516,000	
NJ	Citgo Petroleum Corp.	Pennsauken	x		x	1,018,000	
NJ	Amerada Hess Corporation	Pennsauken	x		x	n/a	
NJ	Amerada Hess Corporation	Perth Amboy	x		x	n/a	
NJ	Chevron USA Products	Perth Amboy	x		x	n/a	
NJ	Stolthaven Inc.	Perth Amboy				n/a	
NJ	Sun Refining & Mrktg Co.	Piscataway	x			95,000	

St	Terminal	City	truck	rail	water	capacity	comments
NJ	Amerada Hess Corporation	Port Reading	x	x	x	5,000,000	
NJ	Amerada Hess Corporation	Secaucus	x		x	n/a	
NJ	Motiva Enterprises LLC	Sewaren	x		x	n/a	
NJ	Gulf Oil Limited Partnership	Thorofare	x			397,654	
NJ	Mobil Oil Corp	Trenton	x		x	67,700	
NJ	Coastal Eagle Point Oil Co.	Westville	x		x	125,000	
NY	Mobil Oil Corp	Albany	x	x	x	881,000	
NY	Agway Petoleum Corp	Albany	x		x	327,800	
NY	Agway Petoleum Corp	Brewerton	x			392,600	
NY	Getty Terminals Corp.	Bronx	x		x	25,445	
NY	Metro Terminal Corp	Brooklyn	x		x	105,000	
NY	Motiva Enterprises	Brooklyn	x		x	n/a	
NY	Star Enterprise/Texaco	Brooklyn	x			132,656	
NY	Amerada Hess Corporation	Brooklyn	x		x	n/a	
NY	Amoco Oil Co.	Brooklyn	x		x	128,000	
NY	Metro Terminal Corp	Brooklyn	x		x	105,000	
NY	Mobil Oil Corp	Buffalo	x		x	513,800	
NY	Agway Petroleum Corp	Geneva	x			113,800	
NY	Citgo Petroleum Corp.	Glenmont	x		x	1,371,884	
NY	Mobil Oil Corp	Glenwood	x		x	77,400	
NY	Mobil Oil Corp	Inwood	x		x	249,300	
NY	Motiva Enterprises	Inwood	x			247,242	
NY	Sun Refining & Mrktg Co.	Johnson City	x			60,000	
NY	Carbo Industries Inc.	Lawrence	x		x	5,900,000	
NY	Stratus Petroleum	Liverpool	x			176,500	
NY	Getty Terminals Corp.	Long Island City	x		x	30,015	
NY	Amerada Hess Corporation	Marcy	x			n/a	
NY	Agway Petoleum Corp	Marcy	x		x	272,800	
NY	Agway Petoleum Corp	Milton	x			159,800	
NY	Amoco Oil Co.	Mount Vernon	x		x	90,000	
NY	Sun Refining & Mrktg Co.	New Windsor	x		x	104,000	
NY	Coastal Oil New York Inc.	New Windsor	x		x	521,000	
NY	Mobil Oil Corp	Newburgh	x	x	x	312,500	
NY	Amerada Hess Corporation	Newburgh	x		x	n/a	
NY	RAD Energy Corp	Oceanside	x		x	228,000	
NY	Petroleum Fuel & Terminals Co.	Rensselaer	x		x	560,000	
NY	Sun Refining & Mrktg Co.	Rensselaer	x		x	414,000	
NY	Amerada Hess Corporation	Rensselaer	x		x	n/a	
NY	Bray Terminals Inc.	Rensselaer	x	x	x	400,000	
NY	Getty Terminals Corp.	Rensselaer	x		x	330,775	
NY	Tosco	Riverhead	x		x	5,200,000	
NY	Amerada Hess Corporation	Rochester	x			n/a	
NY	Agway Petoleum Corp	Rochester	x			174,900	
NY	Coastal Oil New York Inc.	Rochester	x			197,000	
NY	Sun Refining & Mrktg Co.	Rochester	x			150,000	
NY	Mobil Oil Corp	Rochester	x	x		286,200	
NY	Sears Oil Company	Rome	x		x	155,000	
NY	Mobil Oil Corp	Staten Island			x	2,400,000	
NY	Coastal Oil New York Inc.	Syracuse	x			306,000	
NY	Mobil Oil Corp	Syracuse	x			297,300	
NY	Mobil Oil Corp	Syracuse	x			193,400	
NY	Sun Refining & Mrktg Co.	Syracuse	x			212,000	
NY	Sun Refining & Mrktg Co.	Syracuse	x			n/a	
NY	United Refining Co.	Tonawanda	x		x	325,000	
NY	Sun Refining & Mrktg Co.	Tonawanda	x			330,000	

<b>St</b>	<b>Terminal</b>	<b>City</b>	<b>truck</b>	<b>rail</b>	<b>water</b>	<b>capacity</b>	<b>comments</b>
NY	NOCO Energy Corp	Tonawanda	x	x	x	1,220,000	
NY	Citgo Petroleum Corp.	Vestal	x			122,752	
NY	Amerada Hess Corporation	Vestal	x			n/a	
NY	Agway Petroleum Corp	Vestal	x			320,400	
NY	Coastal Oil New York Inc.	Vestal	x			156,000	
NY	Mobil Oil Corp	Vestal	x			115,307	
NY	Amerada Hess Corporation	Warners	x			n/a	
RI	Mobil Oil Corp	East Providence	x		x	1,000,000	
RI	Getty Terminals Corp	East Providence	x	x	x	323,130	
RI	Motiva Enterprises LLC	Providence	x		x	1,685,313	
RI	Citgo Petroleum Corp.	Providence	x		x	446,760	
	Total					89,328,608	