Review of Transportation Issues and Comparison of Infrastructure Costs for a Renewable Fuels Standard

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Contacts

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On June 17, 2002, Senator Jeff Bingaman, Chairman of the Senate Committee on Energy and Natural Resources, requested that EIA provide analysis of eight factors related to the Senate-passed fuels provisions of H.R. 4, the Energy Policy Act of 2002.[1] In response, the Energy Information Administration (EIA) has prepared a series of analyses discussing the market impacts of each of these factors.

Because of the rapid delivery time requested by Sen. Bingaman, each requested factor related to the Senate-passed bill was analyzed separately, that is, without analyzing the interactions among the various provisions. In addition, assumptions about State actions, such as their implementation and timing of MTBE bans, influence the results. Discussions about some of these interactions have been included in order to explain the interconnected nature of such issues.

EIA's projections are not statements of what will happen but what might happen, given known technologies, technological and demographic trends, and current laws and regulations. The *Annual Energy Outlook 2002 (AEO2002*) is used in these analyses to provide a policy-neutral Reference Case that can be used to analyze energy policy initiatives. EIA does not propose, advocate or speculate on future legislative or regulatory changes. Laws and regulations are assumed to remain as currently enacted or in force in the Reference Case; however, the impacts of emerging regulatory changes, when clearly defined, are reflected.

The analyses involve simplified representations of reality because reality is complex. Projections are highly dependent on the data, methodologies, and assumptions used to develop them. Because many of the events that shape energy markets are random and cannot be anticipated (including severe weather, technological breakthroughs, and geopolitical disruptions), energy market projections are subject to uncertainty. Further, future developments in technologies, demographics, and resources cannot be foreseen with any degree of certainty. These uncertainties are addressed through analysis of alternative cases in the *AEO2002*.

Introduction

The Senate-passed version of H.R.4 contains provisions that will eliminate the oxygenate requirement for RFG (reformulated gasoline) and ban the use of MTBE through a nation-wide phase out beginning in 2004. The bill also creates a Renewable Fuel Standard (RFS), mandating that a certain portion of all gasoline sold in the United States will have to be renewable fuels, and that by 2012 the total amount of renewable fuels sold in the United States will be approximately 5 billion gallons per year (BGY).

[1] Letter from Sen. Bingaman to Mary Hutzler, dated June 17, 2002.

This report analyzes the inter-regional transportation issues and associated costs for increased distribution of renewable fuels with the assumption that ethanol will be used to meet the standard. Increasing the use of ethanol to 5 BGY by 2012 more than doubles the current level of ethanol production and could place a considerable burden on the current transportation infrastructure. For each of the transportation modes considered (rail and water), this report examines potential concerns regarding capital cost, equipment availability, and infrastructure capability and provides a detailed breakdown of costs by mode. Pipeline and truck shipment is not addressed in this report because it is not currently considered a cost-effective method of transport due to special handling requirements.

The information presented in this document draws on completed studies regarding future ethanol logistics, as EIA has not performed an independent analysis examining this issue. The most comprehensive work regarding ethanol distribution infrastructure and costs is a report by Downstream Alternatives, Inc. (DAI), *Infrastructure Requirements for an Expanded Ethanol Industry*, performed for the Department of Energy Office of Energy Efficiency and Renewable Energy. The bulk of the information presented here is a summary from the final draft of that report. However, some information from a June 2000 study by the National Petroleum Council (NPC) on U.S. petroleum refining is also presented in this summary.

The DAI study concludes that with sufficient lead-time, the transportation industries could increase capacity to meet increased ethanol transportation demands without serious risk of sustained supply disruption. However, potential areas of concern in the existing distribution infrastructure exist which must be addressed.

Inter-Regional Transportation Issues

Although most logistical issues should be overcome with proper planning, there are concerns regarding capital costs for expanding the current infrastructure, congestion, spatial constraints at terminal facilities, and availability of equipment. These problems arise because of the movement of product from the Midwest to the coastal regions of the United States.

Water

The DAI study did find that potential concerns for barge transport exist. Potential major areas of concern are the availability of compliant vessels with the Jones Act and Oil Pollution Act of 1990, and barge movement in some areas of the U.S. inland waterway system that are already congested or freeze during winter.

The Merchant Marine Act of 1920, otherwise known as the Jones Act, requires that products shipped between U.S. ports must be transported in ships that were built in the United States, U.S. flagged, and manned by U.S. personnel. The Oil Pollution Action of 1990 (OPA90) requires the use of double hulled vessels and further requires the retirement of single hulled vessels from petroleum product service by certain dates based on their manufacture or rebuild date. As a result a number of vessels were retired in the late 1990's with no replacements. Consequently, there is a growing shortage of Jones Act Vessels especially those in "clean product" service.

This is of concern because ethanol shipments from the U.S. Gulf Coast to other U.S. ports would require Jones Act Vessels. The shortage of these vessels and the high costs of using them may lead to a growing preference for rail shipments as ethanol capacity is increased. Although, as the DAI study states, the volume of new ethanol is less than the volume of MTBE it would be replacing,[2] in California 85 percent of MTBE is imported[3] and hence exempt of Jones Act/OPA90 requirements.

OPA90 mandates additional environmental safety requirements for vessels that ship petroleum products, making OPA90 compliant vessels more expensive to use than ones that meet Jones Act requirements alone. Ethanol producers may avoid having to use costly OPA90 compliant vessels by shipping undenatured ethanol, which is not considered a petroleum product. The undenatured ethanol could be shipped in regular Jones Act vessels, rather than OPA90 compliant Jones Act vessels, to a plant holding a Distilled Spirits Plant Permit (DSPP). The permit holder receiving the shipment would not have to pay taxes on the shipment, and the ethanol could be denatured at the receiving port.

A consideration when shipping by ocean vessel is supply reliability. Transit time for product shipped to California via the Panama Canal may be more than a month and an unanticipated delay of 5 to 10 days is not unusual. Terminals will likely need to add more storage to accommodate enough back up inventory as a contingency to such delays.

A large portion of the ethanol transported in an expanded ethanol market would also move in river barges on the inland waterway system. For the 5.1 BGY scenario in the DAI study, such shipments amount to 0.58 percent of current tonnage moved on the inland waterway system. While this is a relatively modest volume increase, it would occur at a time when traffic is already projected to rise 1.3 percent yearly.

Perhaps more importantly, these shipments will originate on portions of the system already experiencing delays at some locks, such as the Missouri, Illinois, and Ohio Rivers all of which connect with the Mississippi and in turn the Gulf Coast. Delays have been caused by locks that are shorter than many barge tows ("trains" of individual barges), necessitating the time-consuming exercise of breaking a tow and reassembly after passing through the lock in two or more segments. In addition, northern reaches of the Mississippi River can be ice-blocked and not navigable during winter. In the case of shipments to the Gulf Coast (to stage product for loading onto ships), shippers may also

[2] Less ethanol than MTBE is required to achieve oxygen content requirements under the Clean Air Act Amendments of 1990, because ethanol contains nearly double the amount of oxygen as MTBE.
[3] California Energy Commission, *Quarterly Report Concerning MTBE Use in California Gasoline: January 1 through March 31, 2002 - Report to the Legislature*, P300-02-002V1 (Sacramento, CA, May 2002).

experience delays at their unloading destination at certain times of the year. All of these factors may contribute to supply disruptions. In addition, further strains will be placed on the inland waterway system through increased shipments of grain based production, whether wet or dry mill, resulting in increased co-products such as Distillers Dried Grain and Solubles (DDGS) and animal feed.

Present travel above St. Louis can be difficult to accurately schedule because of lock delays. Increased movements on the inland waterways may eventually require, or at least would be better facilitated by upgrading certain locks. However, because of environmental considerations, groups may oppose such expansion. Funding for maintenance and infrastructure improvements for the inland waterways system and associated locks comes from the Inland Waterway Trust (50 percent) and the Federal Government (50 percent). Certain maintenance projects are budgeted while funding for improvements would require enabling legislation. Although the Corps currently has plans to upgrade locks causing delays, they have no formal timeline and these projects have not been fully funded.[4]

The DAI study recommends these issues be studied more closely. Specifically, a study should be undertaken to determine what impact the increased ethanol and co-product shipments of an expanded industry would have on the inland waterway system's operability. The study also recommends that the Army Corps of Engineers be kept informed of any industry expansion so that the Corps can contribute to various ethanol-related assessments, and also to ensure they are apprised of any significant industry expansions that might impact their area of responsibility.

Rail

Constraints in the inland waterway infrastructure will lead producers to make greater use of rail. Also, to overcome difficulties from mid-December to mid-February when the upper Mississippi may freeze, producers will likely use staging tankage in New Orleans for swing storage. Inventories of ethanol could be stored in these tanks and supplemented with additional rail car shipments. Also, producers will make use of more 30,000-barrel barge movements, as they are easier to break up into smaller tows and move through locks.

Potential bottlenecks may result from increased railroad transport. In colloquies conducted in spring 2001 by DAI on ethanol logistics, railroad representatives indicated that any real bottlenecks would be in yard space, switch capacity, and at terminals. In some cases, yard space is limited so additional traffic could increase congestion to unacceptable levels. Units would therefore need to be moved out to final destinations quickly. In California, in particular, yard space is extremely limited. While switching capacity there is perceived as adequate, properly timing the switch, terminal receipt, and availability of power were considered potential areas of concern. However, no one felt that these items were an insurmountable problem, but rather areas needing special attention as the market develops.

[4] Personal communication with author of DAI study, Bob Reynolds July 31, 2002.

Other factors in an increased ethanol market will create circumstances that will require increased use of rail transportation. Because ethanol has a higher blending vapor pressure than MTBE (17 PSI, or pounds per square inch, versus 8 PSI) this necessitates the removal of other highly volatile compounds such as butanes or pentanes before blending ethanol, which places additional pressure on product movement by rail at the terminal and refinery sites. Incidentally, this additional step increases cost by around 1 to 1.5 cents per gallon.[5] The need to move these products out of the terminal, while perhaps bringing in other products such as alkylates, to make up for the volume loss from the MTBE and butane/pentane removal, is another area further complicating rail logistics.

Despite these possible problems, the anticipated volume of ethanol to be moved by railroad is a very small fraction of products moved by the industry. The rail freight-car-building industry has the capacity to build equipment at a faster pace than the ethanol industry can increase production from new plants.[6]

The greatest concern expressed in the DAI study was that terminals that are capable of receiving rail are limited in the number of cars they can spot or unload at a given time. Some terminals can spot only 3-5 cars (a typical rail car holds 29,000-30,000 gallons), and even larger terminals cannot routinely spot more than 15-20 cars. Consequently a unit train (100 cars) would need to be broken up into segments.

California in particular may have problems with lack of yard space for rail receipt. According to the July 2001 CEC study on MTBE phaseout[7], there is currently no capability to handle long lines of rail cars at California terminals. Furthermore, if all of California's ethanol was supplied by rail, the study estimates 1,270 to 3,650 additional rail cars would be required to continuously supply the state, raising questions about rail car availability and potential scheduling delays.

According to the DAI study, while many terminals will add rail spurs, space limitation will still result in restrained rail car spotting at terminal facilities. Adding rail spurs to bring trains to terminals is not enormously expensive and participants in the DAI study provided estimates of $75 to $95 per track foot, which equates to $200,000-$250,000 for a half mile spur. The terminal operators would typically be responsible for, and incur the cost of, the rail spur installation. By comparison switch track runs $35 to $45 per foot while main line track can run as much as $200 to $300 per foot, i.e. $1 million to $1.5 million per mile.

The higher cost of main line track is due in part to right of way issues, permitting, environmental assessments and concerns, proximity of residential areas, traffic concerns

[5] Personal Communication with author of DAI study, Bob Reynolds on July 31, 2002.
[6] Downstream Alternatives, Inc., *Infrastructure Requirements for an Expanded Ethanol Industry* (South Bend, IN, Jan. 15, 2002), p. F-19, and *Storage Distribution Requirements for an Expanded Ethanol Industry* presented at EIA NEMS/AEO Conference March 12, 2002. See http://www.eia.doe.gov/oiaf/aeo/conf/reynolds/NEMS.ppt
[7] California Energy Commission, *MTBE Phaseout Update – Costs, Supply, Logistics & Key Challenges*, presented at California Air Resources Board Hearing in San Francisco, CA, July 26, 2001.

and many other such issues. Since most terminals are located near other chemical plants with access to railroads nearby, right of way issues are not expected to be a problem for most terminals that will add rail spurs or switch track for rail receipt.

Turn around times for rail cars vary depending on whether the cars are a small shipment or a unit train. Single cars or groups of a few cars are moved less consistently and therefore take as much as twice the amount of time to reach their destination compared to unit trains. As an example, single car movements or movements of a few cars from Illinois to Phoenix can result in a total of 25 days consisting of 10 days out; 2 days in the yard; 3 days to switch, unload, and prep for return; and 10 days to return. Unit trains could probably be done in 7 days out, 7 days back, plus unloading time for a best turn around time of 15-16 days.[8] Another major factor in turn around time is the type of rail cars. Regular rail cars are unloaded one car at a time per header so that if only one header is available the cars need to be spotted at the header one after another, a time consuming process. To reduce unloading times, the GATX Corporation, a major lessor of tank cars, manufactures cars with a patented "pipeline on wheels" system which can unload 17-18 cars that are connected in tandem and all unloaded through one car at a header. A greater number of headers also will enable simultaneous unloading of several cars, speeding up the process.

Producers will make increasing use of railcars with the GATX system, utilizing unit trains with more headers, which connect to the terminal manifold, and/or increase inventory levels at their terminals. It is worth noting that only a small fraction of all terminals are currently equipped to receive product by rail, barge, ocean vessel, or even truck. According to the DAI study, out of 261 terminals in Petroleum Administration for Defense District (PADD) 1, 116 terminals are equipped to receive product by water, and 22 terminals are equipped for rail receipt. Similarly, out of 95 terminals in PADD 5, 32 terminals can receive product by water, and 16 terminals are equipped for rail receipt.

Infrastructure Costs Associated with Renewable Fuels

The DAI study estimates the infrastructure investment costs and the transportation costs that would likely be incurred if ethanol demand reached 5.1 billion gallons per year (BGY) at unspecified future dates.[9] The infrastructure costs presented are incremental and represent additional expenditures from an established baseline level of 1.8 BGY, which includes the 600 million gallons per year of ethanol needed by California to phase out MTBE. The study intentionally avoids explicit assumptions about a timeline for phasing in ethanol. Rather than providing a "road map" for a RFS, the study provides total costs in current dollars and addresses both terminalling costs at the wholesale level and costs related to retail sales of ethanol and gasoline-ethanol blends.

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Transportation Costs

[8] *Ethanol Logistics Colloquies Overview and Observations*, June 1, 2001, Phase II – ORNL, included as an appendix in DAI's January 2002 study.
[9] Under the proposed RFS, required renewable fuel use would be about 5 BGY by 2012.

Table 1 presents a breakdown of freight costs by PADD associated with transport of ethanol in the 5.1 BGY scenario. In the DAI study analysis, freight costs are expected to be the largest category of costs – far larger than the amortized costs of modifications to petroleum terminals and to retail stations for blends of 10 percent ethanol or less.

The average cents per gallon in Table 1 are provided on an amortized, cost per gallon of ethanol basis. In order to provide a reasonable comparison of program costs, it is necessary to amortize costs for investments over the projected lifetime of the equipment or program. The DAI study used a capital recovery factor (CRF) developed by Technology and Management Services, Inc. (TMS). Assumptions employed in developing the factors considered for the DAI study included a return on investment (ROI) of 10 percent, a tax rate of 34 percent, and a capital replacement increment of 1.6 percent per year. To arrive at an amortized cents per gallon of new ethanol volume, the program cost being amortized is divided by the applicable new annual ethanol volume and then multiplied by these factors for the life cycle of the relevant equipment.

Table 1. Total Freight Costs for Ethanol Transportation for 5.1 BGY Scenario (million 2000 dollars)

		Ethanol Imports from PADD 2*			Shipments within PADDS				Total	
PADD	Ethanol Shipped (BGY)	Ship/ Barge	Rail	Avg. (cents/ gal.)	Truck	Rail	Barge	Avg. (cents/ gal.)	Total Cost	Avg. (cents/gal.)
1	1.3	$57.4	$70.0	9.8	$13.1		$4.0	1.3	$144.5	11.1
2	2.2				$77.9	$12.8	$3.2	4.3	$93.9	4.3
3	0.7	$2.6	$35.3	5.4	$8.0		$0.3	1.2	$46.2	6.6
4	0.1		$4.5	4.5	$0.2			0.1	$4.7	4.7
5	0.8	$51.1	$32.9	10.5	$17.8			2.2	$101.8	12.7
Total	5.1	$111.1	$142.7	5.0	$117.1	$12.8	$7.5	2.7	$391.1	7.7

* Note: Totals may not add due to rounding of individual numbers. Where storage costs are a portion of transportation (e.g., product staging for inter-modal shipments), they are included in freight costs.
Source: Technology and Management Services, Inc., *Information Regarding Ethanol Delivery Infrastructure*, prepared for DAI (Gaithersburg, MD, January 23, 2002). Data taken from Downstream Alternatives, Inc., *Infrastructure Requirements for an Expanded Ethanol Industry* (South Bend, IN, January 15, 2002).

The scenarios analyzed in the DAI report are not specific as to the timing of the ethanol demand levels. Implicit in this scenario is the existence of phased-in demand growth, allowing time for suppliers and those involved in transporting, storing, and selling ethanol to expand their capabilities as demand grows, similar to how a Renewable Fuel Standard (RFS) would be implemented over a period of several years.

According to the study, 21 river barges of 30,000-barrel capacity and 2,549 additional rail cars will need to be added. The study assumes no Jones Act vessels will be added because the volume of new ethanol to be transported by ship is less than the volume of MTBE that it would be replacing by ship. However, as mentioned before, most MTBE is imported and exempt from both Jones Act and OPA90 requirements, bringing this assumption into question. Given the study's assumptions of the geographic distribution of ethanol sales, the placement of proposed plants, and costs of new freight infrastructure and shipping, the estimated amortized average national freights costs for all categories in the 5.1 BGY scenario are 7.7 cents per gallon of ethanol.

The range of freight costs across PADD regions in the DAI study is 4.3 to 12.7 cents per gallon. PADD 2 is not expected to import any of its ethanol; total average freight costs are estimated to be 4.3 cents per gallon. On the other hand, PADD's 1 and 5 will have to import most of their ethanol from PADD 2 by barge, barge to ocean vessel, and rail increasing freight costs above the intra-PADD costs.[10]

Capital Cost Investment

Table 2 below presents estimates of total capital investment for terminal improvements and retail conversions in the study. The estimated amortized average national costs for capital investments are 0.8 cents per gallon of ethanol. At this cost, 495 terminals (58.6 percent of operating terminals) will offer ethanol, 181 terminals will add new ethanol tanks, and an additional 63 existing tanks will be converted to ethanol use. Also, 49 terminals will need to add rail spurs, 287 terminals will need to add blending equipment, and 35,214 retail outlets will make one-time modifications to handle ethanol.

Table 2. Total Estimated Capital Investment for Terminal Improvements and Retail Conversions for E10/E5.7 for 5.1 BGY Scenario (million 2000 dollars)

PADD	New Ethanol Volume (BGY)*	Cost of New Tanks	Cost of Tank Conversion	Cost of Blending Systems	Modifying for Rail Receipt	Contingency	Retail Conversions	Total	Amortized Cost (cents per gallon)
1	1.102	$8.89	$0.65	$24.30	$7.10	$1.26	$6.50	$48.66	0.69
2	1.072	$5.40	$0.31	$33.00	$5.33	$2.02	$7.44	$53.49	0.78
3	0.626	$5.74	$0.34	$22.20	$3.55	$1.24	$5.28	$38.34	0.96
4	0.042	$0.75	$0.02	$2.40	$1.07	$0.12	$0.31	$4.66	1.73
5	0.145	$2.33	$0.06	$4.20	$0.36	$0.24	$1.25	$8.42	0.91
TOTAL	2.987	$23.06	$1.37	$86.10	$17.34	$4.88	$20.78	$153.58	0.80

*Note: Totals may not add due to rounding of individual numbers.
Source: Technology and Management Services, Inc., *Information Regarding Ethanol Delivery Infrastructure*, prepared for DAI (Gaithersburg, MD, January 23, 2002). Data taken from Downstream Alternatives, Inc., *Infrastructure Requirements for an Expanded Ethanol Industry* (South Bend, IN, January 15, 2002).

The NPC study[11] did not address ethanol logistics nearly as comprehensively as the DAI study. The NPC study estimates a cost of $185 million nationwide to modify 225 petroleum product terminals, primarily in PADD 1 and PADD 3. The DAI and NPC studies do not lend themselves well to a comparison. Retail outlet modifications and ethanol freight costs were not estimated by the NPC. Their study focused on supplying a demand of approximately 3 BGY in 2005. Also, the DAI study includes hypothetical plants that, in some cases, reduce the tank size requirements as well as the number of rail

[10] Shell Oil Corporation estimated additional costs for freight of 12.5 cents/gallon in a recent work. *Oil Price Information Service*, Vol. 22, No. 26 (July 1, 2002), p.2.
[11] National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels*, (Washington, DC, June 2000).

spurs required. NPC assumes 100 terminals would need to add rail spurs, whereas DAI estimates only 49. NPC also used higher costs per terminal ($400,000) for blending systems than DAI ($300,000) and estimated the cost for new tanks at 125 terminals to be $450,000 each to install a 25,000-barrel tank. This broad-based estimate of required tanks and tank sizes for terminals differs from DAI's study, which analyzed tankage needs by markets, minimizing tank size.

The estimated costs for new tanks and terminal improvements vary widely in the NPC and DAI studies due to different assumptions and study methodologies. DAI's study minimized tank size and arrived at estimated cost of $14.6 million for new tanks in PADD's 1 and 3. On the other hand, NPC's broad-based estimates led to a cost calculation for new tanks that was closer to $60 million. Such different results show uncertainties involved in estimating the cost of new terminal infrastructure to handle ethanol. It is important to note, however, that due to the NPC study's assumption that 3 BGY of ethanol is shipped to PADD's 1 and 3, an amount nearly 60 percent more than the DAI study assumed, the difference in cost per gallon of ethanol for terminal improvements is much smaller; 0.96 cents per gallon of ethanol in the NPC study compared to 0.79 cents per gallon of ethanol in the DAI study (averaged over PADD's 1 and 3).

Relationship to Previous EIA Studies

The response to Question 2 of Senator Bingaman's request to EIA**, "**Renewable Motor Fuel Production Capacity Under H.R. 4," includes costs for transporting ethanol from the Midwest to the Gulf Coast, West Coast, and East Coast. That report analyzes ethanol production capacity, supply, and the effect on gasoline prices of an RFS.[12]

Most ethanol is currently produced in the Midwest and that is expected to continue over then next 20 years. California is expected to be the only significant new entrant into ranks of ethanol producers. Ethanol is currently being blended primarily in the Midwest. State bans of MTBE in California and New York will soon require more ethanol blending on the East and West coasts. So, the largest share of ethanol movements will be in the Midwest, where costs are lower than those to the coasts (Table 1).

In the analysis of Question 2, the cost of moving ethanol to the West Coast was assumed to be about 4 cents per gallon higher than the latest DAI study. If the DAI costs were included in the response to Question 2, California reformulated gasoline using ethanol would cost about one-quarter cent per gallon less (Table 3). Similarly, East Coast reformulated gasoline using ethanol would be 0.14 cents per gallon lower.

[12] Energy Information Administration, *Renewable Motor Fuel Production Capacity Under H.R. 4 Requested by Senator Bingaman,* (Washington, DC, August 2002).

Table 3. Reduction in Reformulated Gasoline Costs Resulting from Reduction in Waterborne Transportation Costs for Moving Ethanol from the Midwest (2000 cents per gallon)

Destination	Reduction
East Coast	0.14
Gulf Coast	0.35
West Coast	0.25

Sources: Energy Information Administration, Petroleum Market Model input files for *Annual Energy Outlook 2002*, derived from Information Resources, Inc., *United States Ethanol and Methanol Consumption and Pricing Analysis*, (Arlington, VA, Sept. 15, 1994); Downstream Alternatives, Inc., *Infrastructure Requirements for an Expanded Fuel Ethanol Industry* (South Bend, IN, January 15, 2002).

The cost of moving ethanol to the Gulf Coast was assumed to be 6.1 cents per gallon higher in the response to Question 2 than in the DAI study, or 0.35 cents per gallon of reformulated gasoline (RFG) using ethanol. However, much less ethanol is expected to be imported by water into the Gulf Coast than into the East and West Coasts. In the 5.1 BGY scenario, the DAI study estimates that 85 million gallons per year is expected to be imported by water into the Gulf Coast, compared to 540 million gallons into the East Coast and 365 million gallons into the West Coast. The average cost of RFG using ethanol, across all three regions analyzed, is 0.20 cents per gallon higher in the response to Question 2 than in the DAI study. Since RFG is about one-third of all gasoline consumption, average gasoline prices using the DAI transportation costs would be 0.07 cents per gallon lower in the three regions considered than in the response to Question 2.

Conclusion

Expanding the market for ethanol to 5.1 billion gallons per year, more than double current level, results in an estimated average national cost of about 8 cents per gallon of ethanol to transport it to markets, according to a DAI study. These costs are similar to the costs used in EIA's prior analyses of an MTBE ban and RFS. A few major items in the delivery infrastructure will be required before demand reaches this level. Rail terminals able to spot more than a few cars, constraints on the Inland Waterway System, and a possible shortage of OPA90 compliant Jones Act Vessels are some of the issues that must be dealt with to ensure adequacy of gasoline supplies, particularly in California. However, given one year to plan for an MTBE phaseout and Renewable Fuels Standard, suppliers can secure the necessary financing to initiate construction far enough in advance to begin overcoming these infrastructure barriers.

Appendix A:

Letter of Request from Senator Jeff Bingaman, June 17, 2002.

United States Senate

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510-6150

ENERGY.SENATE.GOV

June 17, 2002

Dr. Mary Hutzler
Acting Administrator
Energy Information Administration
1000 Independence Avenue SW
Washington, DC 20585

Dear Acting Administrator Hutzler:

The Senate passed version of H.R.4 contains a number of provisions affecting fuels markets that require additional analysis prior to final conference decisions. First, the oxygenate requirement for RFG would be eliminated and the states would be allowed to ban the use of MTBE beginning in 2004, a national phase out would follow. Also beginning in 2004, a certain portion of all gasoline sold in the U.S. will have to be from "renewable fuels", this requirement will affect all refiners and gasoline markets. The combination of these two factors alone has the potential to significantly impact US motor fuels markets.

As we all know too well, every previous significant change to fuel formulations has resulted in severe price volatility in various US motor fuels markets. Each time, the Committee on Energy & Natural Resources has held hearings to review the problems in an effort to avoid or at least mitigate future recurrence of such dislocations. The Energy Information Administration (EIA) has also investigated and reported on these various transitions. We should be able to apply what we have learned from these past market transition experiences to ease the implementation of these various changes that will start to take effect in 2004.

Therefore, I am requesting that the EIA analyze the potential market implications of the Senate-passed fuels provisions in H.R.4 combined with known and anticipated regulatory changes. This should include specific analysis of the following factors:

1. The expected volumetric shortfall in fuels supplies with an effective MTBE ban in 2004;
2. Actual renewable fuels production capacity, supply, and constraints and the effect on price;
3. Inter-regional transportation issues and associated costs for renewable fuels;

4. The potential effect of operating the mandate on a fiscal year, (i.e. beginning in October) vs. calendar year basis;
5. The environmental impact of the simultaneous implementation of the low sulfur and Mobile Source Air Toxic (MSAT) gasoline regulations and a national ethanol mandate;
6. The impact on gasoline price and supply when many additional ozone non-attainment areas come under the new 8-hour ozone standard;
7. The potential cost and supply impacts associated with individual states seeking to protect air quality through the removal of the one-pound vapor pressure waiver for gasoline blended with ethanol;
8. The potential effect/role of implementation of a national menu of fuels to address the proliferation of boutique fuels.

As earlier requests have noted, it would be helpful to have this study completed as soon as possible. Should you have any questions, regarding this request, please contact Jennifer Michael at the Committee, at (202)224-7143. I thank you in advance for your assistance.

Sincerely,

Jeff Bingaman
Chairman, Senate Committee on
Energy & Natural Resources

cc: file