Renewable Motor Fuel Production Capacity Under H.R.4

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Contacts

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Introduction

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*.

Near-Term Renewable Motor Fuels Capacity

The authors of H.R. 4 write that, "The term 'renewable fuel' means motor vehicle fuel that is produced from grain starch, oilseeds, or other biomass; or is natural gas produced from a biogas source, including a landfill, sewage waste treatment plant, feedlot, or other place where decaying organic material is found…"

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

Although many known, and perhaps some unknown, renewable fuel sources qualify under the definition, through 2020 the requirement for renewable content of motor vehicle fuel is expected to be met primarily by ethanol blended into gasoline at volume fractions of 10 percent or lower.

There are several ways to produce ethanol. H.R. 4 makes specific reference to emerging technology for conversion of cellulose to ethanol. Each gallon of ethanol produced from cellulosic feedstocks is to be counted as 1.5 gallons of renewable motor vehicle fuel. Ethanol can be produced from cellulose by conversion of the cellulose to sugar and fermentation. It can also be produced by gasification of cellulose and subsequent catalytic conversion to ethanol. Both technologies are still at the pilot stage. It is hoped that this credit for cellulose ethanol will accelerate its commercialization.

The established technology for ethanol production is fermentation of sugars from sugary plants or from plant starches converted to sugar. Corn is the most common raw material for ethanol production in the United States. There are two methods of ethanol production from corn: wet milling and dry milling. All ethanol production requires water, but wet mills are so named because the first step in the process is soaking the corn in hot water to allow for subsequent separation of the grain into components. Wet mills generally produce corn oil and the animal feed ingredients corn gluten meal and corn gluten feed in addition to ethanol. Some of the starch may be diverted to starch or sweetener production. The dry mill process begins with the grinding of the grain before water is added. Dry mills produce distillers' dried grains, also an animal feed, along with ethanol. Existing ethanol capacity is about half wet mill and half dry mill. New plants are expected to be dry mills, because the capital cost per gallon of dry mill capacity is considerably lower than that for wet mill capacity.

Whether dry mill or wet mill, ethanol plants yield 2.65 gallons of fuel ethanol per bushel of corn input. The cost of corn per gallon of ethanol is projected to be $0.88 (2000 dollars) in 2004 (Table 1). Energy requirements vary by technology. Existing wet mills use 40,848 British Thermal Units (Btu) of coal and 10,212 Btu of natural gas per gallon of ethanol on average. Existing dry mills are expected to use 18,900 Btu of coal, an average of 18,900 Btu of natural gas, and 1.09 kilowatt-hours of electricity per gallon by 2004. New dry mills are expected to use an average of 37,800 Btu of natural gas and 1.09 kilowatt hours (or 3712 Btu) of electricity per gallon.[23] Dry mills are expected to

[2] Hosein Shapouri, James A. Duffield, and Michael Wang, *The Energy Balance of Corn Ethanol: An Update*, AER-813 (Department of Agriculture, July 2002), p. 9. (http://www.usda.gov/oce/oepnu/aer-813.pdf)

[3] Existing wet mills are assumed to use 80 percent coal and 20 percent natural gas. Existing dry mills are assumed to use 50 percent coal and 50 percent natural gas.

reduce consumption of coal and natural gas over the forecast period.[4] Energy cost projections are based on industrial sector projections for 2004.[5]

Table 1. Ethanol Production Cost by Technology, 2004 (2000 dollars per gallon)

	Existing Wet Mill	Existing Dry Mill	New Dry Mill
Capital cost	*NA*	*NA*	$0.234
Corn cost	$0.883	$0.883	$0.883
Energy cost	$0.088	$0.134	$0.169
Other Operating cost	$0.372	$0.15	$0.15
Coproduct credit	-$0.377	-$0.214	-$0.214
Average variable cost	**$0.966**	**$0.953**	$0.988
Average total cost			**$1.222**

NA=Not Applicable.
Sources: Mark Yancey. Presentation at 2002 International Fuel Ethanol Workshop and Trade Show, Springfield, Illinois, June 25, 2002. *Points to Consider When Building an Ethanol Plant*, Site Selection. BBI International. Other operating cost, Existing Wet Mill: Energy Information Administration, Petroleum Market Model input files for *Annual Energy Outlook 2002*. Coproduct credits were estimated from historical data.

Dry mills' revenue from the sale of distillers' dried grains and wet mills' revenue from the sale of corn gluten feed, corn gluten meal, and corn oil is reflected in the coproduct credit for each type of plant. Existing plants will operate as long as average variable costs are covered. Capital costs already incurred are not applicable to the decision to operate. New plants will only be built and operated if average total costs are covered.

EIA does not collect ethanol capacity data, but collects monthly production data. So far in 2002, United States ethanol production has averaged 128,000 barrels per day. If production continues at this same pace, 1.962 billion gallons will be produced for the entire year.[6] Ethanol production in 2001 was 1.765 billion gallons.[7]

[4] Energy Information Administration, Petroleum Market Model input files for *Annual Energy Outlook 2002*. Estimated dry mill energy use in 2004 is 37,800 Btu per gallon.

[5] Energy Information Administration, online version of *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (December 2001), Reference Case Forecast, Annual 1999-2020, Table 3. (http://www.eia.doe.gov/oiaf/aeo/pdf/aeo_base.pdf)

[6] Energy Information Administration, *Petroleum Supply Monthly*, DOE-EIA-0109 (2002/06) (June 2002), Appendix D. (http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_monthly/psm_historical.html)

[7] Energy Information Administration, *Petroleum Supply Monthly*, DOE-EIA-0109 (2002/01) (January 2002), Appendix D.

The Renewable Fuels Association (RFA), an ethanol industry trade group, maintains a list of ethanol producers, their plant sizes, and their feedstocks. The producers on the RFA list have existing capacity of 2.4 billion gallons per year. Of that, approximately 2.3 billion gallons are located in the Midwest region. All of the capacity being added, about 460 million gallons, is in the Midwest. About 55 million gallons of existing capacity are dedicated to feedstocks other than corn. Alternative feedstocks include milo, or grain sorghum, waste from beverage alcohol production, potato waste, sugar, and cheese whey. In addition to corn, barley and wheat starch are used by some producers. All of the new capacity is to be corn-fed and is expected to come online in 14 months or less from the date of this report. The Nation will have about 2.86 billion gallons of ethanol capacity available in 2004. This number is reflected in the graphs and discussion below.

Table 2. Ethanol Production Capacity by Census Division (million gallons per year)

Census Division	Existing Capacity	Capacity Under Construction
East North Central	705.5	120.7
West North Central	1591.6	340.0
South Atlantic	4.0	
East South Central	64.0	
Mountain	27.5	
Pacific	9.7	
Total	**2402.3**	**460.7**

Source: Compilation of online document *Ethanol Production Facilities*, Renewable Fuels Association. (http://www.ethanolrfa.org/eth_prod_fac.html)

The United States imports a small quantity of fuel ethanol as well. In 2001, 10.5 million gallons were imported from Canada, and 2.8 million gallons were imported from Costa Rica. One reason for the low level of imports is the tariff of $0.54 per gallon that applies to most imported fuel ethanol to offset the gasoline excise tax exemption for ethanol-blended gasoline.

EIA Study

Four MTBE/rewewable fuels policy cases were analyzed using the National Energy Modeling System (NEMS).[8]

• The No State MTBE Ban case, which is the base case for this analysis, assumes that the 17 States with pending MTBE bans do not implement their bans, allowing the cost of the RFS to be evaluated from today's levels. The States are: Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri,

[8] The scenario assumptions for these cases are similar to those used in Energy Information Administration, *Impact of Renewable Fuels Standard/MTBE Provisions of S. 517 Requested by Senators Daschle and Murkowski*, (Washington, DC, April 15, 2002).

Nebraska, New York, Ohio, South Dakota, and Washington. Existing oxygenate mandates continue in this case.

• The 17-State MTBE ban case assumes that the 17 States proceed to phase out MTBE as planned. Existing oxygenate mandates continue in this case.

• The RFS case adds the RFS on top of the State MTBE bans, but not a Federal MTBE ban. Existing oxygenate mandates continue in this case.

• The 87-percent reduction MTBE reduction case assumes that H.R. 4 becomes law, but that Texas, which currently uses about 13 percent of all MTBE blended in the United States, opts to continue using MTBE. This assumption was drawn from an earlier study for Senators Murkowski and Daschle.[9] In this case, as in the bill, oxygenate mandates are repealed and the RFS takes effect.

The results of interest are ethanol consumption and gasoline price effects. Figure 1 shows the effects of the four sets of scenarios on ethanol consumption. If the State MTBE bans are not implemented, ethanol consumption is projected to remain approximately constant at 2.5 billion gallons per year. This is above the level of the RFS for 2004. Although existing ethanol capacity and capacity under construction have been added in anticipation of an MTBE phaseout, producers will find it economic to sell ethanol for blending into conventional gasoline as long as the ethanol blenders' tax credit remains in place. In the base case about 146,000 barrels per day of ethanol are blended in 2006, but only 40,000 barrels per day of that are blended into RFG.

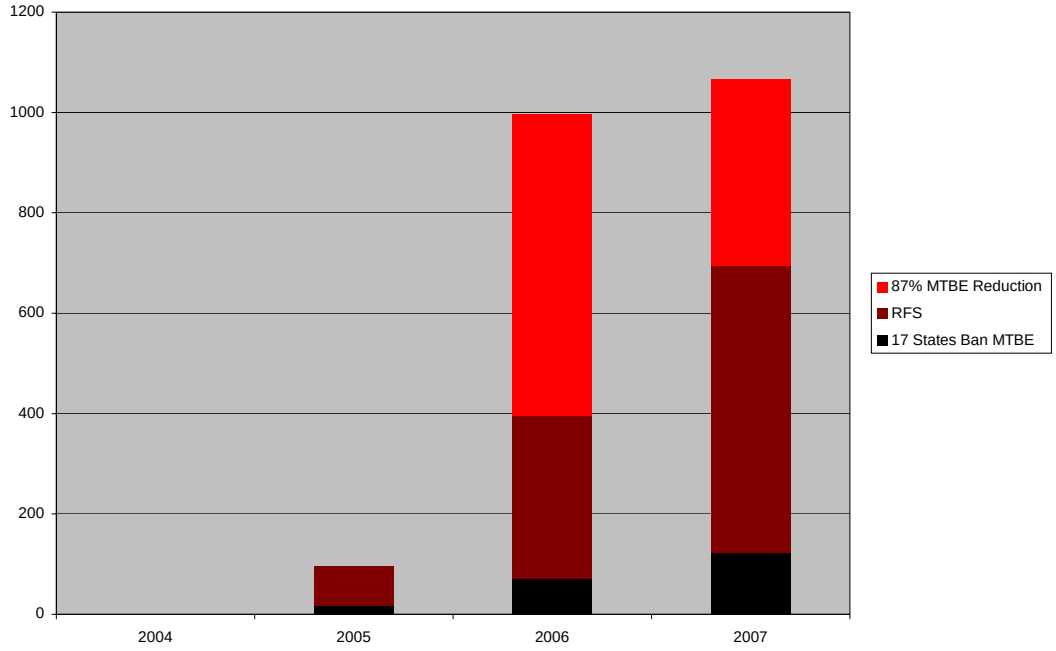
The schedule set down by H.R. 4 requires 2.3 billion gallons of renewable transportation fuel in 2004 and 2.6 billion gallons in 2005. These volumes can be produced from existing ethanol plants and plants currently under construction. Industry capacity for 2004 is expected to be 2.86 billion gallons per year if all the plants under construction are completed on schedule. The requirement for 2006 is 2.9 billion gallons. Assuming a plant size of 40 million gallons annually, 1 new plant is needed to meet the requirement in 2006. Another 8 plants must be added to produce the 3.2 billion gallons required for 2007. More severe MTBE reductions result in ethanol consumption over and above the levels required by the RFS case with only 17 States banning MTBE. Projected ethanol consumption under the 87-percent MTBE reduction case is 3.496 billion gallons in 2006 and 3.565 billion gallons in 2007. The number of new plants necessary by 2006 under this scenario grows from 1 to 16. Then, 2 more are needed by 2007.

In the RFS case 173,000 barrels per day of ethanol are blended into gasoline and of that, 120,000 barrels per day are blended into RFG in 2006. About 96 percent of ethanol is projected to be produced in the Midwest in that year. In the 87-percent MTBE ban case, case 212,000 barrels per day of ethanol are blended into gasoline and 183,000 barrels per day of that are blended into RFG in 2006. In this case ethanol plant expansion occurs primarily in the Midwest, with 97 percent of ethanol production projected to occur in the Midwest in 2006.

[9] Ibid.

Either scenario is technically feasible, as construction of an ethanol plant is about a 2-year process. However, construction and engineering firms are facing significant demands for labor related to the 2004 reduction of sulfur levels in gasoline and the 2006 reduction of sulfur levels in diesel fuel. As a result, ethanol producers may find new plant construction somewhat more costly than usual in 2006.

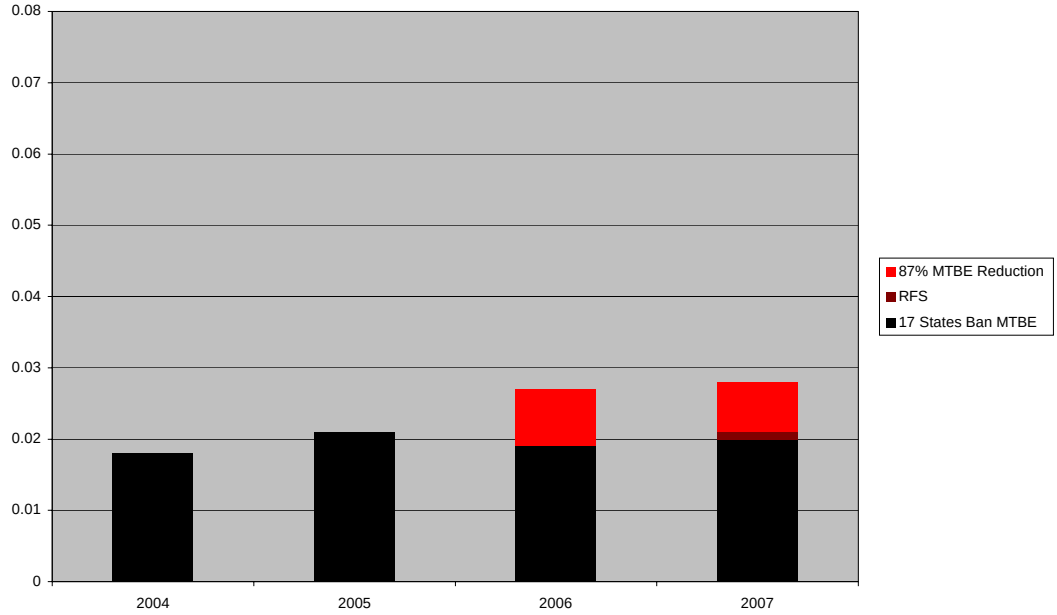
Figure 1. Ethanol Consumption Increments Over No State MTBE Ban Case (million gallons per year)



Sources: National Energy Modeling System date codes ENsXmXoX.d082302a, ENs1mXoX.d082302b, ENs1mXrf.d082302a, and ENs1m087.d082302c

Figure 2 shows the gasoline price effects in the four cases. The baseline for gasoline price comparisons is the case where no States implement MTBE bans. The pending State MTBE bans are projected to increase average national motor gasoline prices by 1.8 to 2.1 cents per gallon. The RFS has very little additional effect. Further MTBE reductions in the 87-percent reduction case increase gasoline prices to 2.7 cents per gallon in 2006 and 2.8 cents per gallon in 2007 over what would be expected without any MTBE reduction.

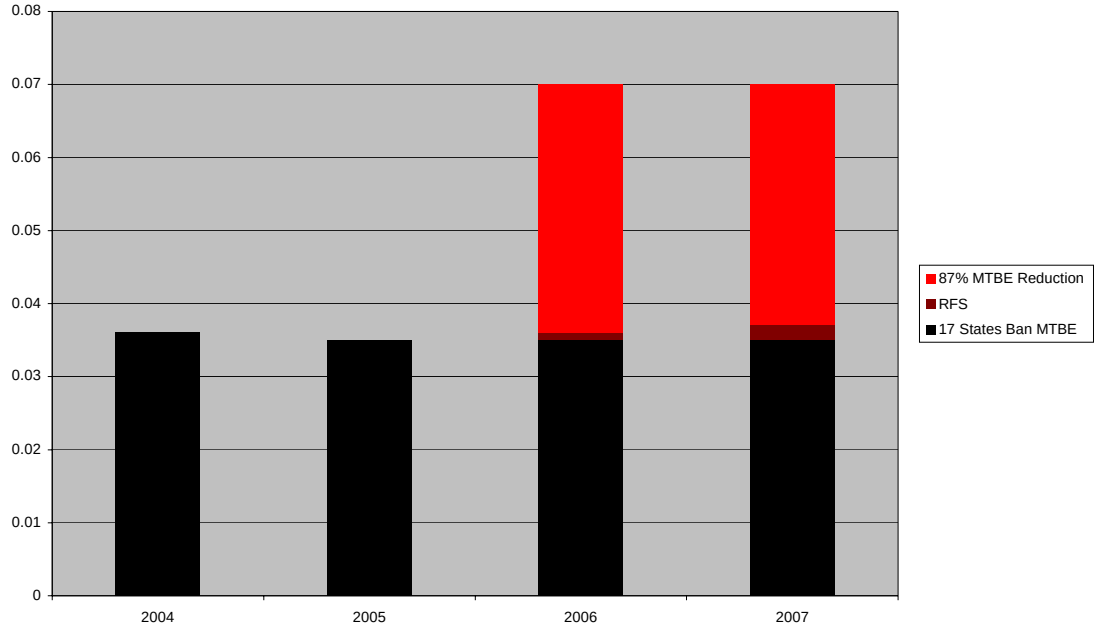
Figure 2. National Average Motor Gasoline Price Increments Over No State MTBE Ban Case (2000 dollars per gallon)



Sources: National Energy Modeling System date codes ENsXmXoX.d082302a, ENs1mXoX.d082302b, ENs1mXrf.d082302a, and ENs1m087.d082302c

When RFG prices are broken out from overall gasoline prices, a similar pattern with greater projected cost impacts is observed (Figure 3). The pending State MTBE bans have the largest impact on national average RFG prices--3.5 to 3.6 cents per gallon. The RFS case results are again not much different from the State MTBE ban results. The RFS and the 17 State MTBE bans increase projected gasoline prices by at most 3.7 cents per gallon over the no State MTBE ban case. The 87-percent reduction case increases RFG prices by 7.0 cents over the case with no State MTBE bans.

Figure 3. Average RFG Price Increments Over No State MTBE Ban Case (2000 dollars per gallon)



Sources: National Energy Modeling System date codes ENsXmXoX.d082302a, ENs1mXoX.d082302b, ENs1mXrf.d082302a, and ENs1m087.d082302c

An unintended consequence of the RFS might be an ethanol plant construction boom leading to overcapacity and depressed prices. If would-be ethanol plant builders expect low prices in the future, they may choose not to enter the market. If everyone thinks and acts the same way, not enough ethanol plants will be built, and a gap between the required quantity and ethanol industry capacity could emerge. An ethanol industry consultancy has indicated that banks financing ethanol plant construction could be expected to refrain from lending on projects leading to possible oversupply.[10] Firms wishing to begin or expand ethanol production can therefore expect banks to discipline industry expansion.

Passage of the energy bill may not resolve all the demand-side uncertainties in the ethanol market because the legislation leaves several issues unresolved. In particular, since the legislation does not specify exactly how the RFS volumes are to be shared among refiners, blenders, and importers, and how the credit trading program will work, the regional demand for ethanol cannot be projected with certainty. In addition, the legislation allows States to petition for a waiver or reduction of the RFS, which could reduce ethanol demand from what is projected here and could cause uncertainties in the level of ethanol demanded in specific years.

[10] Conversation with Mike and Kathy Bryan, Bryan and Bryan International. At International Fuel Ethanol Workshop and Conference, Springfield, Illinois, June 26, 2002.

Ethanol plant emissions have recently drawn the scrutiny of the Environmental Protection Agency. Drying the distillers' grains emits carbon monoxide and volatile organic compounds, which may have negative health effects. Some of the organic compounds also smell unpleasant, causing complaints from residents near ethanol plants. The probable solution is thermal oxidation of the exhaust from the grain dryer, which reacts the organic compounds with oxygen to form water vapor and carbon dioxide.[11] New ethanol producers are expected to address these concerns up front by designing their plants with thermal oxidizers.

The ethanol industry is expected to continue to concentrate in the Midwest regions, where grain feedstocks are most plentiful.

Comparison to Previous Analysis of Energy Legislation

This work projects slightly smaller gasoline price impacts than EIA's prior analysis of S. 517 performed at the request of Senators Murkowski and Daschle. The latter study projected an average gasoline price increase of a little over 3 cents per gallon and an average RFG price increase of a little under 8 cents per gallon under the RFS, an 87-percent MTBE reduction, and waiver of the oxygenate requirement for RFG. Such a waiver allows the RFS to be met by blending ethanol into conventional gasoline rather than blending ethanol into RFG, which is more complicated. Since the S. 517 study was completed, EIA obtained updated data on the ethanol industry that show greater capacity, lower projected corn feedstock costs, and lower production costs. This is the main reason for the slightly smaller estimated gasoline price impacts (by about 0.4 cents per gallon for all gasoline) of the RFS and MTBE reduction.

The S. 517 study also projected that the RFS would have a smaller impact on ethanol consumption than the State MTBE bans in 2005. The S. 517 study projected cellulose ethanol production of 133 million gallons per year in 2005. Each gallon of cellulose ethanol is credited as 1.5 gallons of renewable fuel under the RFS. But, cellulose ethanol technology has not progressed as rapidly as expected. EIA now expects production of ethanol from cellulose no earlier than 2010. Corn ethanol production must make up the projected loss of 170 million gallons (with the 150-percent credit) toward the RFS if it is enacted. As a result, the current analysis projects a larger impact on corn ethanol use for the RFS than the State MTBE bans in 2005.

Conclusion

The ethanol industry is expected to be able to supply the volumes of ethanol required to phase out the use of MTBE and to meet a renewable motor fuels requirement under consideration in Congress. The industry is expected to have more than the capacity needed to meet the renewable fuels standard in 2004 and 2005, since it has 461 million gallons of capacity under construction. Anywhere from 9 to 18 new plants are needed to meet the RFS or an 87-percent reduction in MTBE volume in 2007. But since ethanol plants only take about 2 years to build, timing will not be a problem in the scenarios

[11] *World Fuels Today*, June 3, 2002. Hart Publications, Potomac, Maryland.

analyzed in this paper. It is important to note that ethanol plant construction requires adequate lead time and a fairly certain projection of ethanol demand. The additional volumes of ethanol projected in this analysis may not be available without a renewable fuels requirement or MTBE regulation enacted well in advance of the desired date of implementation.

In the absence of an RFS or nationwide MTBE ban, the industry can meet the demand for ethanol in the 17 States that have banned MTBE without adding a single plant beyond those currently being built. In the 87-percent MTBE reduction case, RFG prices are expected to increase 7.0 cents per gallon, and national average prices are expected to increase about 2.8 cents per gallon, compared to a case in which no States implement their MTBE bans.

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