Final Regulatory Impact Analysis

and

Summary and Analysis of Comment

For:

Renewable Oxygenate Requirement

for Reformulated Gasoline

June 29, 1994

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I.   Oxygenate Supply Issues

A.   <u>Introduction</u>

        In the NPRM, EPA proposed to require that renewable oxygenates be used to meet 30 percent of the 2.0 weight percent oxygen requirement for the RFG program. However, EPA had only limited information on whether or not adequate supplies of renewable oxygenates would be available without disrupting existing markets for such oxygenates or incurring excessive costs. To gather additional information, EPA requested comments concerning these issues in the proposed rule. Comments were requested on the appropriate level of the renewable oxygenate requirement, leadtime requirements associated with providing adequate renewable oxygenate supplies, the potential need for a phase-in period, and any other supply-related issues. In response, EPA received considerable information on the current and projected supply of renewable oxygenates, and some additional information regarding the logistics of renewable oxygenate distribution. In response to the comments, EPA analyzed how much renewable oxygenate refiners of RFG could blend, and how much the renewable oxygenate suppliers could supply. This analysis looked at the 1995 and 1996 time frame to verify whether the proposed 30 percent requirement could be met for 1995, and if not, when such a requirement could be met. In addition to analyzing the proposed 30 percent requirement in 1995, a two-year phase-in of the program was evaluated. This phase-in would require that 15 percent of the 2.0 weight percent RFG oxygen requirement be met with renewables in 1995. The renewables requirement would increase to 30 percent of the RFG program's 2.0 weight percent oxygen requirement in 1996.

        The analysis examined each element of the renewable oxygenate supply process separately. The first step was to determine which renewable oxygenate would dominate the market during the early years of the program. Second, the projected demand for these oxygenates was determined. Third, feedstocks for the production of these oxygenates were examined to determine whether sufficient feedstock supplies would be available. Fourth, EPA examined the adequacy of projected production capacity for the dominant oxygenates in 1995 and 1996. Finally, EPA investigated whether transportation and distribution networks, such as storage and blending, were adequate to support the program during each of the first two years of the program and how fast additional needed facilities could come on line.

B.   Renewable Oxygenates Likely to Be Used

     EPA evaluated the oxygenates that could potentially be made
from renewable sources to determine which of them would most
likely be used to meet the requirements of this program. The
renewable oxygenate or combination of multiple renewable
oxygenates that could be supplied and distributed was analyzed to
determine whether the full 30 percent requirement could be met in
1995 without disrupting existing renewable oxygenate markets or
incurring large price increases for renewable oxygenates. The
list of potential renewable oxygenates evaluated included
ethanol, methanol, ethyl tertiary butyl ether (ETBE), methyl
tertiary butyl ether (MTBE), tertiary amyl methyl ether (TAME),
tertiary amyl ethyl ether (TAEE), and diisopropyl ether (DIPE).
There are significant interrelationships between the various
oxygenates which can affect their potential production volumes.
For example, the production of renewable MTBE and TAME depend on
the amount of renewable methanol produced. The production of
ETBE and TAEE would be limited by the amount of ethanol that is
available. In addition, production of one type of ether can be
converted over to the production of another type. For example,
MTBE production can be converted over to ETBE production with the
addition of relatively modest amounts of equipment.

     EPA collected data to determine the current production
levels of various renewable oxygenates. Table I-1 below
summarizes the current level at which oxygenates are being
produced from renewable feedstocks. Current production of
ethanol, which is produced exclusively on a renewable basis, is
within the range of 1.15 - 1.25 billion gallons of ethanol per
year.[1] Only very limited information was found on the renewable
production levels of methanol, ETBE, MTBE, TAME, TAEE and
diisopropyl alcohol. ETBE production is reported by Information
Resources Incorporated (IRI) to be about 4 million gallons per

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     [1] The lower value is based on information supplied by the
Department of Energy (*Weekly Petroleum Status Report*, Energy
Information Administration, Department of Energy, Washington, DC,
March 1994). The higher value is based on information collected
by Information Resources, Inc. (*Alcohol Outlook*, Information
Resources Incorporated, Arlington, VA, Issues: January – April
1993; *21st Century Fuels*, IRI, Arlington, VA, Issues: May –
December 1993).

year.[2] To EPA's knowledge, no commercial-scale production of renewable methanol is currently in existence. However, in comments received from Brightstar, that company indicated that it is now running pilot tests for renewable methanol production. No evidence was found that diisopropyl alcohol (the limiting feedstock for DIPE production) was being produced in any quantities as a renewable oxygenate. Based on the available information, EPA is confident that aside from ethanol, the current production for all of these other renewable oxygenates combined is less than 10 million gallons per year, much lower than current ethanol production levels and representing a small portion of the renewable oxygenate program's requirements. A more complete discussion of the production levels of ethanol can be found in section D.

Table I-1: Domestic Production of Renewable Oxygenates

Renewable Oxygenate	Estimated Current Annual Production (million gal.)
Ethanol	1250
ETBE	< 4
TAEE	N/A
Methanol	N/A
MTBE	N/A
TAME	N/A
Diisopropyl Alcohol	N/A

N/A = Production levels not available or extremely small

The planned expansion in production capacity for each of these renewable oxygenates was also considered, since capacity coming on-line over the next several years could allow these oxygenates to play a significant near-term role in the renewable oxygenate program. Based upon the available information, EPA determined that there is considerable renewable ethanol production capacity ready to come on-line, in new plant

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[2] *21st Century Fuels*, Information Resources Incorporated, Arlington, VA, February 1994.

construction or projects being financed, while production of other renewable oxygenates will remain limited. A detailed analysis of future growth potential for ethanol production (described below in section D) determined that an estimated 600 million gallons of ethanol will come on-line over the next several years. An investigation of the potential capacity for production of renewable methanol (to be used to produce renewable MTBE or TAME)[3] revealed that a limited volume may be available. For example, Brightstar stated in comments to the Agency that they plan to install three facilities to produce 90 million gallons per year of renewable methanol. Their production, however, is not expected to come on-line until sometime in 1996. With the exception of Brightstar's plans, however, little capacity to produce renewable methanol is expected to come on-line rapidly, not only because it will take time to design and obtain funding for new facilities, but because practical limitations currently exist on how readily ether producers can take advantage of the tax credits and exemptions available for renewable fuels and commonly used by ethanol blenders. In their comments, Arco Chemical stated that the subsidy for renewable alcohols contained in ethers is generally inaccessible to oxygenate producers and refiners under the situations in which the ether is blended into gasoline. Since methanol is not typically added directly to gasoline due to volatility and materials compatibility concerns, and since the costs of production of these oxygenates are not insignificant, without access to the tax credits there is little economic incentive to produce renewable methanol, even with a requirement for renewable oxygenates in reformulated gasoline. As a result, this analysis assumes that the renewable oxygenate requirement would be met primarily with ethanol. ETBE and other renewable ethers were assumed to play a relatively limited role, at least in the first few years.

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[3] Since methanol is not blended directly into gasoline due to volatility and materials compatibility issues, it will be made into an ether for blending in RFG.

C.   Renewable Oxygenate Demand

EPA first determined the program's demand in terms of
ethanol consumption based on the proposed 30 percent requirement.
Determining ethanol consumption, however, was complicated by the
seasonal nature of this program. Ethanol blended as an alcohol
can only earn renewable credits when used during the non-VOC
control season. As a result, the ethanol demand resulting from
the renewables program will be concentrated during the months
when non-VOC-controlled RFG is being produced. One implication
of this demand pattern is that (at least in the near term) winter
ethanol production capacity will have to supply the bulk of the
renewables requirement. Summer ethanol production will probably
be used in non-RFG markets (since its use would not receive
credit under the renewable oxygenate program), converted to ETBE,
or, when possible, stored for winter use. However, as discussed
later in this section, the available ethanol storage capacity is
relatively small. Furthermore, while non-commingling renewable
oxygenates such as ETBE would earn credits toward the renewable
oxygenate requirement throughout the year, the quantity of such
oxygenates is projected to be limited, particularly during the
early years of the program (as discussed in more detail below).
As a result, EPA's analysis of renewable oxygenate supply focused
on the amount of ethanol that could be produced during the times
when VOC-controlled RFG is not expected to be produced. To
simplify this discussion, the terms "non-VOC control season" and
"wintertime" will be used interchangeably, as will "VOC control
season" and "summertime."

Before the amount of new ethanol demand could be determined,
the volume of reformulated gasoline covered by the Federal RFG
program had to be quantified. A similar analysis performed to
establish the Phase II standards of the reformulated gasoline
program (presented in the Regulatory Impact Analysis for the RFG
final rule) was revised to adapt it to this program. The list of
nonattainment areas covered by the RFG program was updated to
reflect the current opt-in situation; the updates included the
addition of the nonattainment areas within Kentucky and
Wisconsin. Furthermore, the California areas of Los Angeles and
San Diego were included in this analysis since they are required
to meet the requirements of the renewable oxygenate program (the
enforcement exemption granted for the Phase II California RFG
program does not extend to the renewable oxygenate program). As
in the previous analysis, the ratio of the population in these
nonattainment areas to the state population was applied to 1992
state gasoline use determined by the Federal Highway

Administration. A 5% spillover rate[4] was assumed. This is
smaller than the 10% spillover rate used for the Phase II RFG
analysis because it was only necessary to account for the RFG
sold outside the covered areas and not spillover from the summer
season to the non-summer season, since the renewable requirement
applies year-round. After these changes and updates were entered
into the analysis, the renewable oxygenate program was determined
to apply to 38.7 billion gallons of reformulated gasoline per
year.

The ethanol demand for the renewables program was determined
from the volume of reformulated gasoline calculated above. The
renewables program requires that 30 percent of the 2.0 weight
percent RFG oxygen requirement be met with renewable oxygenates.
At 2.0 weight percent, refiners would blend ethanol at on average
about 5.76 volume percent. As a result, the 30 percent renewable
oxygenate program would require an estimated 670 million gallons
of ethanol to be blended into gasoline. In actual practice,
refiners may blend greater or lesser amounts of ethanol in each
gallon of RFG, depending on such factors as tax credits, price
and availability of various oxygenates, and the demands of toxics
compliance. Furthermore, more renewable oxygenate may be blended
in gasoline in one season as opposed to the other. Refiners also
may blend renewable ethers such ETBE to meet the renewable
oxygenate requirement. While the use of such ethers would not
alter the total amount of ethanol required by today's rule (since
the oxygen in these ethers is derived from ethanol), it would
reduce the amount of winter ethanol demand, since ETBE blended
into summertime RFG would receive credit towards the renewables
requirement.

The amount of new ethanol demand resulting from today's rule
is somewhat smaller than 670 million gallons, however, since some
ethanol is currently sold in states having areas covered by the
RFG program. Two sources of data for ethanol use within
individual states are available to determine the amount of
ethanol currently blended into RFG areas. One is 1992 data from
the Federal Highway Administration (FHwA). For that database,
FHwA relies upon each state's monthly reporting of ethanol use
within their state. However, FHwA has acknowledged that the
amount of ethanol reported to be blended in their database may be
low due to under-reporting by some states. Furthermore, FHwA has

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[4] Spillover is the estimated percentage increase in
reformulated gasoline use that would occur from RFG sold either
before or after the requirements apply, or outside the covered
nonattainment areas.

not yet published reports on the amounts of ethanol blended in 1993.

Ethanol blending data is also available from Information Resources, Inc. (IRI).[5] This data is based on monthly reporting by ethanol producers on the amount of ethanol distributed to individual states. Because the data was collected in 1993, it should reflect increased ethanol use in oxygenated fuels areas. A simple verification was made of the IRI data by comparing the aggregate quantity of ethanol blended with gasoline by IRI with that reported by DOE. Based on IRI data, a total of 1250 million gallons of ethanol were blended into gasoline in the U.S. in 1993.[6] DOE determined that 1150 million gallons of ethanol were blended with gasoline in 1993.[7] The IRI total is about 9 percent higher than the DOE figure. Considering the difficulty involved in obtaining reliable ethanol use data, the 9 percent difference between the IRI and DOE figures is relatively small, and within acceptable limits. Since the IRI data provided a detailed breakdown by month and State and was more recent than the FHwA data, it was selected for use in further analyses.

Based on the IRI information, approximately 180 million gallons of ethanol are already being consumed annually in RFG areas during the months in which EPA would expect non-VOC-controlled gasoline to be produced (equivalent to 8 percent of the total oxygenate demand under the RFG program). On an annual basis (including all months), the value would be 280 million gallons per year. The former value was obtained by adding up the amount of ethanol/gasoline blends distributed to the states with RFG programs during the period when non-VOC controlled RFG is expected to be produced (approximately September 15 through March 31); this information is presented in Table A-1 in Appendix I. IRI verified in a telephone conversation that their estimates of ethanol blending assumed all ethanol blends to be 10 percent ethanol, so the amount of ethanol blended was determined applying a 10 percent multiplication factor to the IRI reported ethanol blend volumes. Then, the total volume of ethanol blended by each covered state during that period was adjusted based on the

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[5] *Alcohol Outlook*, Information Resources Incorporated, Arlington, VA, Issues: January - April 1993; *21st Century Fuels*, IRI, Arlington, VA, Issues: May - December 1993.

[6] Ibid.

[7] *Weekly Petroleum Status Report*, Energy Information Administration, Department of Energy, Washington, DC, March 1994.

state's population fraction living in the nonattainment areas. This yielded the estimated amount of ethanol being blended in the nonattainment areas. The annual figure was determined in the same fashion, except that the ethanol consumption for all 12 months was added together. For some states this methodology could be conservative since the ethanol use is probably exclusively being used in the nonattainment areas. However, they may also over predict ethanol use since, as discussed above, the IRI data shows higher ethanol use than other published estimates.

The net renewable oxygenate demand can now be determined. The difference between the aggregate program demand with a 30 percent requirement and the amount of ethanol already being used in the RFG areas during the non-VOC control season reveals that approximately 490 million gallons of additional ethanol production would be needed annually. This estimate only takes into account the ethanol that has been used in RFG areas prior to introduction of the RFG program, however. As discussed below in section D.2. and in more detail in section IV.A.1., construction and expansion of additional ethanol production capacity was underway even prior to publication of the renewable oxygenate proposal. Presumably much of this new capacity was intended to supply a portion of the new demand for oxygenates created by the RFG program. Based on the analysis in section IV, approximately 155 million gallons of new ethanol may have been brought on-line to fulfill the needs of the RFG program in 1995. This effectively reduces the new ethanol demand resulting from the renewable oxygenate program to 335 million gallons annually.

D.   Renewable Oxygenate Supply

1.   Feedstock Capacity

The first step in evaluating the adequacy of renewable oxygenate supply is to determine whether sufficient feedstocks would be available. According to comments received from agricultural interests, corn is the feedstock for 90 percent of current ethanol production and is expected to provide much of the feedstock for new ethanol capacity added in the near term; about 2.5 gallons of ethanol are produced from each bushel of corn. A total of 8.7 billion bushels of corn are produced in an average year.[8] Hence, in 1992 approximately 360 million bushels

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[8] According to information provided by John W. McClelland of USDA, "Memorandum for Richard Wilson, Director, Office of Mobile Sources, U.S. Environmental Protection Agency," June 20,

(approximately 4 percent of average annual corn production) was used to produce an estimated 900 million gallons of ethanol. Therefore, estimated increase of 335 million gallons of new ethanol from this program would require about 134 million bushels of corn, if the entire amount of new renewable oxygenate production were to come from corn. A 134 million bushel increase in corn production would represent a 1.5 percent increase in U.S. corn production when compared to the amount of corn produced in 1992.[9] In addition, other feedstocks can be used to produce renewable oxygenates, including waste products from farms, dairy operations, bakeries, and the soft drink industry; feedstocks from cellulosic sources such as grasses and fast-growing energy crops, and feedstocks from such sources as municipal solid waste.

2.   Ethanol Supply and Production Capacity

As discussed in the Preamble to this rule, EPA believes for a number of reasons that displacement of ethanol from existing markets to meet the demand of the renewable oxygenate program should be avoided to the extent possible. Shifting ethanol from existing markets to RFG markets would not stimulate the development of additional capacity or the introduction of more advanced renewable fuels production technology. The use of ethanol from new or expanded plants would displace more fossil energy than would ethanol from existing plants (as described in section II). In addition, the costs to this program of displacing ethanol may be significant and may lead to supply disruptions. If diversion of ethanol from existing markets is to be minimized, then the ethanol required to meet the renewables requirement must come from existing but unused ethanol production capacity ("latent" capacity), new ethanol production capacity, increased imports, or reduced exports. As discussed below, changes in imports and exports is not expected to make significant quantities of ethanol available to satisfy the renewables requirement. As a result, the following analysis focuses on the amount of available latent and new ethanol capacity.

Latent ethanol production capacity was evaluated by taking the difference between the existing domestic demand and operational capacity. As stated above, 1993 ethanol consumption

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1994.

[9] The total ethanol demands of this program, 490 million gallons annually, would consume 195 million bushels of corn, or about a 2% increase from 1992 production levels.

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nationwide has been determined to be approximately 1.25 billion gallons. In addition, EPA received comments from an ethanol producer which projected that 1994 ethanol production would be 1.25 billion gallons; presumably this level was determined based on anticipated demand. Hence, for the purposes of this analysis, current ethanol consumption was assumed to be 1.25 billion gallons per year.

The U.S. Department of Agriculture estimated that the current ethanol production capacity is 1.3-1.4 billion gallons per year. The Renewable Fuels Association (RFA) submitted a list of existing and planned ethanol plants and their operational capacity (this information is presented in Appendix I as Tables A-2, A-3, A-4 and A-5). This list also suggested that current ethanol operational production capacity is nearly 1.4 billion gallons per year. Since the aggregate ethanol production capacity from the list falls within USDA's ethanol capacity range, this list was used as the basis for this portion of the analysis.

Based on the difference between the ethanol production capacity and the current domestic ethanol consumption estimates, EPA determined that there may be as much as 150 million gallons of annual capacity that is either not being used or is being used to supply ethanol for export markets. However, only approximately 80 million gallons would be supplied from current excess capacity during the winter season. To the extent that some portion of this latent capacity represents production that cannot be realized due to scheduled and non-scheduled maintenance, this analysis assumes that the majority of such down-time will occur in the summer months when demand is lowest. Thus, it will not impact the latent capacity available for winter production.

In addition to latent capacity, a considerable amount of new ethanol production capacity is expected to come on-line during the remainder of 1994, and in 1995 and 1996. According to USDA, 500 million gallons of new capacity can come on line by early 1995. Another estimate of new ethanol production capacity was provided by the RFA; this information is presented in Appendix I. Table A-3 describes the capacity and start-up dates of ethanol plants currently under construction. Table A-4 lists plants which have planned expansions. Finally, Table A-5 describes the capacity of plants in the financing or engineering stage of being built. Based on this information, around 600 million gallons of new annual capacity could potentially come on line by the end of 1996.

The amount of production available for 1995 and 1996 was projected for each new plant according to their projected start-up dates. The estimated start-up dates for the list of plants in Table A-3 was used to determine when these plants would start on line. Because most plants require a short trial period before producing product, the end of the quarter was used for the start of production and no production was counted during the VOC control period. The 1996 production capacity for these plants was determined by only counting the production during the non-VOC control period. Since no start-up dates were given for existing plants that will undergo plant expansions, start-up dates one year after initiation of the RFG program were assumed for these plants. One year was considered sufficient since plant expansions often only require de-bottlenecking of existing units and less engineering and hardware than new plants.[10] The same methodology was use to calculate the new 1996 production capacity. The final list of planned ethanol plants in Table A-5, which are in financing and engineering also do not have estimated start-up dates. These plants were assigned start-up dates from 1.5 to 2 years away.[11] On average these plants were projected to supply ethanol for 5 months during 1996 (not all during the winter season). The results from these tables are summarized in Table I-2 below.

Table I-2: Projected New Ethanol Production Capacity*

Current Plant Status	1995 New Ethanol Production	1996 New Ethanol Production
Under Construction	73	127
Planned Expansion	20	37
Financing/Engineering	0	89
Total:	93	253

*Relative to 1993

The projected new ethanol plant production in 1995 and 1996 can now be compared with the program demand to determine if the new production coming on line can satisfy the demand. This comparison is made below in Table I-3. Two comparisons are made; one is for the proposed program with a 30 percent renewable

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[10] *Chemical Engineer's Handbook*, Perry, Robert H., McGraw Hill Book Co., Fifth Edition, 1973.

[11] Ibid.

oxygenate requirement in 1995, and the other is for a phased-in program with a 15 percent requirement in 1995 and a 30 percent requirement in 1996.

Table I-3: Summary of Ethanol Supply/Demand (MM gal) and Need for Displacement

Program Requirement	Proposed: No Phase-in 30% in 1995	Phase-in 15% in 1995	Phase-in 30% in 1996
New Renewable Oxygenate Ethanol Demand	670	335	670
Existing Ethanol Demand in RFG Areas During Winter[1]	180	180	180
Net New Winter Capacity Required	490	155	490
Current Winter Excess Capacity	80	80	80
New Winter Capacity	90	90	250
Potential Shortfall (Displaced from Existing Markets)	320	---	160

The analysis of the proposed program shows that the new ethanol supply from excess wintertime capacity and new plants coming on line could supply a projected 170 million gallons per year over the course of 1995. Thus, an estimated 320 million gallons of ethanol would have to be displaced from existing markets to meet the program demand. On the other hand, when a phase-in is assumed, the 170 million gallons of ethanol supply in 1995 would meet the projected new demand caused by the renewable oxygenate program for that year. In 1996, the estimated new supply of 330 million gallons per year would meet much of the 490 million gallon per year wintertime demand, although there may still need to be approximately 160 million gallons per year that

would have to be displaced from existing markets or satisfied with other renewable oxygenates.

There are ways that the market could respond to meet the new demand that would minimize the displacement of ethanol from existing, non-RFG markets. First, existing ethanol storage capacity could be used to store ethanol produced during the summer for use during the winter. The ethanol stocks are recorded by DOE and reported on a monthly basis. In 1993 ethanol stocks reached 116 million gallons and declined to 75 million gallons during that year.[12] Since the inventory changed by about 40 million gallons during that year, a minimum of 40 million gallons of summer production would be available in the winter. This value may be conservative as it doesn't indicate the potential amount of ethanol storage that may be available, however, no comments were received on this matter for EPA to determine a higher value, nor is the information readily accessible.

Imports could potentially provide another avenue for meeting the program's demand, while exports would detract from that potential supply. Several comments were received on this issue. One commenter pointed out that unlike petroleum, imports comprise a relatively small fraction of the ethanol consumption in the U.S. One commenter stated that according to the International Trade Commission, the U.S. exported about 33.5 million liters, or about 9 million gallons, of fuel grade ethanol in the period of January through November in 1993. The same commenter stated that imports were recorded at 8 million liters, or about 2 million gallons, in that same period in 1993. These volumes combined amount to less than 1% of total annual U.S. ethanol consumption. Other commenters stated that ethanol imports are not expected to increase significantly in response to this program. They stated that imports are discouraged because the tax credits available to domestically-produced ethanol are not extended to imported ethanol, except for that which is covered by the Caribbean Basin Initiative. However, no comments were received nor was information uncovered that would suggest that there is any appreciable expansion of ethanol production planned in the Caribbean Basin.

Changes in demand from existing markets also could change the amount of ethanol available. For example, demand for ethanol and other oxygenates may decrease as more carbon monoxide (CO)

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[12] *Weekly Petroleum Status Report*, Energy Information Administration, Department of Energy, Washington, DC, March 1994.

nonattainment areas reach compliance and end their wintertime oxygenated fuel programs. Since the start of the oxygenated fuels program in 1992, Syracuse, NY, Cleveland, OH, and Duluth, MN are areas which have ceased their programs, and other states with oxygenated fuels programs for their CO nonattainment areas have initiated the process to do so. Conversely, as pointed out by one commenter, the Minnesota legislature has approved an oxygenate program which requires 2.7 weight percent oxygen in all gasoline sold year-round in all CO nonattainment areas beginning October 1, 1995 and state-wide beginning October 1, 1997. If the entire program in 1997 were to be met with ethanol, the state would need about 120 million gallons of ethanol. According to the commenter, Wisconsin is another state which also considered such a program, though it has not yet been signed into law. For this analysis, no net change in renewable oxygenate demand from existing markets is expected because the decrease in demand caused by the termination of State oxygenated fuel programs could be offset by the increase in demand from the State of Minnesota.

3.   ETBE Capacity

     Additional renewable oxygenate supply is expected to come from the production of ETBE. ETBE will likely be made from summertime ethanol production (as well as winter ethanol), since ETBE made from renewable ethanol receives credit towards the renewables requirement year-round. Since current ETBE production levels are relatively small and the leadtime required to convert MTBE plants to ETBE production is fairly long, ETBE is not expected to provide a significant contribution to the renewables requirement in 1995. However, considerably more capacity could come on line in 1996.

     ETBE offers several advantages to refiners over ethanol or MTBE. Unlike ethanol blends, ETBE blends can be shipped through pipelines without difficulty. Although there are no physical limitations for transporting ethanol blends through pipelines, there are process limitations. (Some materials compatibility concerns may exist, but these could be overcome by replacing those parts which are of concern with materials which are compatible with both ethanol and petroleum products.) Petroleum product distribution systems pick up moisture through condensation during product storage and shipment which collects to form pools of water at certain points in the pipeline system. Because gasoline and gasoline/ether blends are not miscible with the water, the moisture does not impact product quality. However, ethanol is miscible with water, so the water will adsorb into the ethanol portion of the ethanol/gasoline blend. If enough moisture adsorbs into the ethanol, then the ethanol/water

mixture may separate from the gasoline and lead to driveability problems when the mixture is combusted in automobiles and trucks. To prevent this scenario, ethanol is usually transported directly to the terminal where the gasoline is pumped into trucks for retail distribution and blended at that point.

Another advantage of ETBE over ethanol and MTBE is its higher volumetric octane value. ETBE's high octane value coupled with the large displacement of gasoline it causes when blended with gasoline to meet the oxygen requirements results in the largest octane boost of these three oxygenates. As refiners reduce the aromatic and olefinic portions of their gasolines to meet RFG program requirements, they may need additional octane to meet their octane requirements. Table I-4 below compares the octane values of ETBE, ethanol, and MTBE, and the volumes of the oxygenates necessary to meet the oxygen requirements. ETBE also has a lower blending RVP than ethanol or MTBE, which in the near term would permit refiners who use ETBE to remove less butane to reach a desired RVP level. Beginning in the year 2000, ETBE's low blending RVP should be even more attractive when the more stringent Phase II performance requirements for RFG take effect. (EPA's Complex Model indicates that much of the additional decrease in VOC emissions required in 2000 can be met by further lowering the RVP of the RFG.) The blending RVP of ETBE ethanol and MTBE are also summarized in Table I-4. Finally, the larger volume of ETBE than MTBE or ethanol that is needed to satisfy RFG's oxygen requirement results in a larger dilution of undesirable gasoline properties, such as sulfur, than would otherwise occur.

Table I-4: Oxygenate Qualities[13, 14]

Item	ETBE	Ethanol	MTBE
Octane (R+M)/2	112	115	110
Blending RVP (psi)	4	18	8
Volume Percent For 2.0 Wt.% Oxygen	13	5.8	11.2
Water Solubility Wt.%	1.2	Infinite	4.3
Total Cost* ($/gallon RFG) versus MTBE	0.008	-0.004	0.000

*   From RFG Regulatory Impact Analysis; cost takes into account relative values for fuel extender, RVP, Octane, Oxygen effects, and blender's tax subsidy for ethanol and ETBE. Oxygenate prices were assumed to be $1.01/gallon for ETBE, $1.20/gallon for ethanol, and $0.70/gallon for MTBE.

As shown in Table I-4, ETBE typically costs more to produce than MTBE or ethanol per unit oxygen. Because of these cost disadvantages and because the RFG requirements do not yet apply, current ETBE production levels are only about 4 million gallons per year. However, for the reasons explained above, ETBE production is expected to grow even without this program since some refiners will want to use ETBE to achieve the low RVP levels needed to meet RFG's Phase II VOC performance standards. The benefits for blending ETBE into gasoline may be far less attractive if ether producers, refiners or terminal operators effectively cannot take advantage of the tax subsidy. According to Arco Chemical, if gasoline continues to be marketed as it is marketed today, only about 15 percent of the gasoline would conveniently allow for the use of the tax subsidy since that is the gasoline which is sold directly by the refiner in the retail

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[13]   *Oxy-Fuel News*, IRI, Arlington, VA, September, 13, 1993.

[14]   Regulatory Impact Analysis, Reformulated Gasoline Program Final Rule, Environmental Protection Agency, December 13, 1993

market.[15] In the case in which the tax subsidy cannot be claimed
for ETBE blended into RFG, the oxygenate cost data in the RIA for
the RFG program final rule shows that the incremental cost of
ETBE-blended RFG would increase from 0.008 cents per gallon to
0.038 cents per gallon.

Regardless of the economics, large amounts of additional
ETBE capacity cannot be expected for 1995 due to limitations on
how quickly MTBE plant conversions can occur. Commenters from
the oil industry stated that MTBE plants could be converted to
produce ETBE in one to three years, while those from the ethanol
industry stated that such conversions could be made within 3 - 6
months. Comments from ether producers suggested that more than
one full year is necessary to convert MTBE plants to ETBE
production. The oil industry commenters said that additional
tanks may be needed at ether production facilities to switch
between feedstocks and oxygenates during the year. The oil
industry commenters also stated that up to a full year is needed
to acquire construction permits and complete the requisite
engineering work. Based on this information, EPA has assumed
that conversion of MTBE plants to produce ETBE will require from
six months to three years, and several months of trial production
may be needed before full production of ETBE can commence. Given
the current situation, EPA does not expect significant amounts of
ETBE production to be possible until the summer of 1996.

Furthermore, the conversion of MTBE plants to ETBE
production could reduce oxygenate throughput (relative to MTBE
throughput) due to a number of different factors. The reduction
is caused by differing reaction conditions, the different nature
of the reactants involved and how each plant can handle the
differing process conditions. Second, ETBE is a larger molecule
than MTBE, for the same amount of oxygen, the production in terms
of oxygen output will tend to decrease. Third, if plants do not
have splitters for recovering unreacted alcohol or for removing
moisture contained in the alcohol, neither of which can easily be
tolerated, the process may have to be altered and the reaction
rate will suffer accordingly.

Overall oxygenate throughput at the level of aggregate
production would also decrease as a result of ETBE use. As
ethanol is reacted to form ethers, the ethanol would simply be

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[15] Letter to Richard D. Wilson, Director of the Office of
Mobile Sources, Environmental Protection Agency, from Thom J.
Edlu, Director, Federal Government Relations, Arco Chemical
Company, April 18, 1994.

converted from one form of oxygenate to another. However, the MTBE production that would have occurred at that ether plant will no longer exist, resulting in a decrease in total oxygenate throughput. Nevertheless, oxygenate shortages are not expected to occur in the short term since additional oxygenate production capacity is coming on line over the next several years. Conversely, renewable oxygenate shortages that could occur would be prevented by reacting summertime ethanol, which cannot count as a renewable oxygenate during the summer, to produce ETBE which would count as a renewable oxygenate during the summer.

E.   Ethanol Distribution Issues

1.   Transportation

     The analysis also investigated whether the additional ethanol produced to meet the requirements of this program can be transported from where it would be produced to where it would be consumed. In the short term, most of the ethanol produced for this program will be produced in the Midwest (as shown in Tables A-3, A-4, and A-5). According to the Army Corps of Engineers (Corps), water-based transportation is the most economical method of shipping ethanol both within the Midwest and from the Midwest to East Coast and West Coast markets. For plants and markets without access to water-based transportation, railway transportation is the most likely transportation mode.[16] EPA has analyzed each piece of the transportation network, specifically: 1) the river barge capacity on the Mississippi River, 2) the ship or ocean barge capacity between the Gulf of Mexico and East and West Coast markets, and 3) the transportation capacity for ethanol movement from ports to retail markets.

     Based on a 1992 report by the Army Corps of Engineers on the status of barge traffic using U.S inland waterways, the transportation by barge of the new ethanol production resulting from today's renewable oxygenates program would represent a very small increase in the demand for U.S. river barge capacity.[17] As stated above, this program is projected to require that an additional 490 million gallons of ethanol is consumed in

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[16]   Letter to Lester Wyborny, Environmental Protection Agency, from Lloyd G. Antle, Chief, Navigation Division, Corps of Engineers, Department of the Army, March 23, 1994.

[17]   The 1992 Inland Waterway Review, IWR Report #92-R-7, U.S. Army Corps of Engineers, October 1992.

reformulated gasoline areas during the winter months. Because of the proximity of the Midwest to ethanol production, which provides a significant transportation cost advantage for its use there, refiners supplying the Midwest are expected to exclusively blend ethanol in reformulated gasoline. In addition, the Illinois state ethanol tax subsidy would make blending ethanol at 3.5 oxygen weight percent (10 volume percent ethanol) even more economical than shipping it to other markets. Based on this scenario, the Midwest is expected to blend as much as 170 million gallons of the newly blended ethanol. Thus, an estimated 320 million gallons of ethanol would be shipped to the Gulf for consumption there or for shipment to other markets.

The report by the Army Corps of Engineers shows that 185 million tons of cargo were shipped on the lower Mississippi in 1990, 27 percent of which were petroleum products. The 320 million gallons of ethanol shipped through the Gulf would add another million tons of cargo per year, or less than a 1 percent increase in the total shipment tonnage on the Lower Mississippi. This value is much smaller than the 2 - 3 percent annual increase in cargo shipped on that segment of the Mississippi over the last several years. Even if only the movements of petroleum were considered, the additional ethanol shipment would amount to just 2% of the total petroleum cargo shipped. Because the ethanol production facilities are spread out throughout the Midwest, ethanol shipment will originate from the many rivers which flow into the Mississippi. The Illinois waterway, which is the waterway that connects the Mississippi river to Lake Michigan, would likely see much of the ethanol shipments to the markets in the Midwest. If all the 170 million gallons of ethanol transported to the Midwest markets were shipped through the Illinois Waterway, the new cargo would add only about 1 percent to the total amount of cargo shipped through that system, or add less than 5 percent if only petroleum products were compared. Other waterways presumably would realize a smaller impact than the Illinois Waterway.

Once the ethanol reaches the Gulf, the quantity which will be shipped to the East or West coast must be transferred to ocean-going freighters or tankers. According to trade information collected by the U.S. Department of Commerce and shared by the Port of New Orleans, the tonnage shipped out of the Gulf is more than adequate to supply the shipping requirements demanded by today's rule.[18] The 320 million gallons of ethanol

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[18] Facsimile to Lester Wyborny, Environmental Protection Agency, from Colleen Quinn, Port of New Orleans, June 2, 1994.

that would be shipped down to the Gulf amounts to approximately 1.06 million tons and would increase the 32 million tons of current shipments from New Orleans by about 3 percent. If only petroleum shipments were considered, then the ethanol tonnage exported from New Orleans would represent approximately a 33 percent increase. However, petroleum imports to New Orleans exceeds exports by a factor of four, which means that these unloaded vessels may be seeking another compatible cargo, such as ethanol, to ship out of New Orleans.

Not all the ethanol transported out of the Gulf to other markets would have to be shipped by ocean-going vessels, however, when ETBE use becomes more attractive and some of the ethanol can be sold to ether producers in the Gulf area for conversion to ETBE. ETBE can be blended into gasoline and shipped by pipeline to other markets on the East Coast. RFG sent up the pipeline that is intended to be blended with MTBE would be blended at the refinery and transported through the pipeline as a gasoline-MTBE blend. If ETBE were to be substituted for MTBE, the volume shipped through the pipeline would not change substantially (since a similar volume of ETBE is required to achieve the same oxygen content), thus there are no expected differences in volumes shipped through the pipeline by this rulemaking.

The transportation of the ethanol/gasoline blends from the terminals, where the blending would occur, to the retail outlets is not expected to change relative to the shipment of MTBE blends. The volume of fuels and the heat content of the two fuels are approximately equal, thus the same number of tank trucks is expected to make the same number of trips. The loading time may be a little longer to splash blend ethanol relative to loading MTBE blends; however, this added time would be insignificant compared to the total time of delivering the cargo.

2.   Storage and Blending Capacity

In addition to issues of sufficient production of ethanol and transportation from the point of production to their final markets, the remaining lead-time issue is that associated with ethanol storage and blending capacity at the terminals where it is blended with gasoline. When the ethanol is off-loaded at its end-use market, it must be stored in large terminal storage tanks. The capacity of these tanks must be sufficient to contain the entire shipment. Once off-loaded, the ethanol then must be blended with gasoline. Some terminals splash-blend ethanol with essentially no additional equipment or facilities, while others use more sophisticated blending equipment. EPA did not receive comments of a nature sufficient to fully evaluate the adequacy or

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inadequacy of current ethanol storage and blending facilities. In order to determine whether adequate storage and blending capacity exists to support the renewable oxygenates program, EPA estimated the storage and blending capacity being used to meet the current demand for ethanol in the RFG areas and compared that with the storage and blending capacity that would be necessary to meet the new program requirements.

To estimate the current storage and blending capacity, EPA examined the peak monthly ethanol blending rates reported by IRI for each RFG market during 1993. On the assumption that this peak represents a level of ethanol blending which the blending and storage facilities are designed to handle (at minimum) and that historically lower monthly ethanol blending rates are due to fluctuations in demand, EPA extrapolated this peak blending rate over the entire non-VOC control season to estimate the current blending capacity available to support the renewable oxygenate program. The results of this analysis are shown in Table I-5.

Table I-5: Ethanol Storage and Blending Capacity in RFG Markets

State (RFG areas only)	Peak Market Share[1]	Winter Ethanol Blending Capacity[2] (MMgals)	% of total RFG that contains renewable oxygenates[3]
Illinois/ Indiana	36	59	2.6
Kentucky	16	9	0.4
Wisconsin	13	18	0.8
Midwest Total		86	3.8
Connecticut	13	10	0.5
Delaware	36	7	0.3
D.C.	36	5	0.2
Maryland	3	4	0.2
New Jersey	8	10	0.5
New York	29	60	2.7
Pennsylvania	19	38	1.7
Virginia	17	19	0.9
Northeast Total		153	7.0
Texas	4	9	0.4
California	5	20	0.9
Total		268	12.1

[1]   Peak market share for ethanol blended in any month in 1993 based on IRI data.

[2]   Peak volume of ethanol blended in any month in 1993 prorated over the assumed 6.5 months of non-voc controlled gasoline production and weighted based on non-attainment area population to statewide population.

[3]   Peak volume from previous column expressed as a percentage of the total oxygenate demand of the RFG program on an ethanol equivalent basis.

Based on this analysis, adequate tankage and blending equipment exists for roughly 12 percent of the oxygenate required by the reformulated gasoline program to be supplied by ethanol during the winter months only. This is well short of the total 30 percent required by the program, and even short of a 15 percent phase-in level. In order to implement the program smoothly, this shortfall can be made up by the combination of three means: first, pass a greater volume of ethanol through existing tankage and blending equipment; second, construct new ethanol storage and blending capacity at terminals; and third,

supplement ethanol blended at terminals with ETBE blended at refineries.

It is reasonable to assume that some additional ethanol could be blended at the existing facilities by increasing the throughput of storage tanks and blending equipment, particularly in the Midwest where the close proximity to ethanol production facilities allows for greater flexibility in receiving and blending ethanol shipments. In addition, it is unlikely that all of the existing facilities were designed to operate at their current peak levels with no provisions made for ethanol market growth. Furthermore, some blenders may be constrained by the volume of hydrocarbon blendstock they can blend with ethanol, rather than by the volume of ethanol they can blend with hydrocarbon blendstock. Such blenders would be able to blend ethanol at concentrations greater than 2.1 weight percent oxygen, thereby generating excess oxygen and renewables credits for trading.

EPA also received comments noting that refiners can work in tandem to meet the renewable oxygenate requirements through such mechanisms as product exchange options. Under this mechanism, one refiner or terminal operator agrees to store and distribute one blendstock (i.e., premium grade) for the other refiner or terminal operator, and in turn the second refiner or terminal operator would maintain a different blendstock (i.e., intermediate grade) for the first. This would free up some tankage which could be used for ethanol storage. A similar but unidirectional arrangement called a throughput agreement could be made between two or more refiners or terminal operators. In this case, a blendstock for a particular area is stored and distributed by another refiner or terminal operator and reimbursement is made with money instead of with product. This option would allow a refiner or terminal operator with the facilities to blend ethanol for other refiners or terminal operators to do so.

In addition, new ethanol blending capacity is likely to have become available since 1994, in keeping with projected increases in ethanol use, regardless of the impacts of this program. Such increases, along with the potential additional ethanol blending capacity that exists and the actions that refiners can take as single entities or in cooperation with other refiners, would seem to give the refining industry sufficient ethanol blending capacity to meet a 25% increase in ethanol blending (from 12 percent of the minimum 2.0 weight percent oxygen required under the RFG program to 15 percent) by 1995.

It is not reasonable, however, to assume that the above listed options could increase ethanol throughput by the 150 percent necessary to achieve the full 30 percent requirement. Meeting the 30 percent requirement would require that refiners take additional steps to increase storage and blending capacity. Two options seem to be available to refiners to meet the 30 percent requirement. The first is building additional storage and blending capacity, the second is relying on ETBE capacity to come on line.

As discussed above no appreciable ETBE production capacity is expected to be available until the summer of 1996, and that amount of capacity cannot be determined with certainty. As a result, refiners in conjunction with terminal operators are most likely to meet the full 30 percent requirements of the program through the addition of new ethanol storage and blending capacity. Based on comments from the oil and ethanol production industries, the addition of such facilities would require a number of steps, which include obtaining permits, the construction of new storage and blending facilities, and the time and effort to make them fully operational. The time for these steps vary, but commenters stated that it could range between approximately 6 and 18 months. Thus, sufficient time would not be available to bring additional ethanol storage and blending facilities on-line for use until the fall of 1995. As stated above in the discussion on transportation, much of the increased ethanol use will occur in the Midwest. Thus, most of the required storage and blending facilities would be required there.

To the extent that ETBE is blended with RFG, it would reduce the need to install additional storage and blending facilities. Refinery-blended ETBE would not require specialized blending facilities at terminals, and would be blended in the same fashion as MTBE. The use of ETBE would reduce considerably the 150% increase in ethanol blending capacity that would otherwise be necessary by 1996.

F.   Summary and Discussion of Comments

EPA received a number of comments regarding renewable oxygenate supply and distribution. Some of these comments expressed support for one or more provisions included in the proposed rule; others expressed opposition to one or more provisions but did not provide sufficient justification or explanation to allow the Agency to analyze their concerns in detail. EPA did use information provided in comments in its analysis of oxygenate supply and distribution capacity and leadtime presented above where the information was considered reliable.

1.   Definition of "Renewable Oxygenate"

EPA received comments expressing concern that imports of ethanol could increase under the renewable oxygenate program, and some commenters recommended that only domestic renewable oxygenates be counted towards the renewable oxygenate requirement. EPA also received several comments opposing any requirement that renewable oxygenates be restricted to domestically-produced renewables, as well as other comments arguing that existing trade regulations would either limit the extent of ethanol imports or prevent the imposition of restrictions on ethanol imports. The final renewable oxygenate program does not distinguish between domestically-produced and imported renewable oxygenates, nor does it alter existing trade regulations. EPA does not believe it has sufficient justification to regulate domestic and imported renewable oxygenates differently, in part because the energy and potential environmental benefits of the renewable oxygenate program are largely unaffected by the location where renewable oxygenates are produced.

2.   Displacement of Ethanol from Existing Markets

EPA received a comment from the City of Chicago which urged that the renewables program permit the current level of ethanol use in non-RFG areas to be maintained. The Society of Independent Gasoline Marketers of America (SIGMA) noted in their comments that removal of ethanol from existing markets could increase emissions in those markets. Another concern raised in several comments was the potential for disruption in either the oxygenate or the RFG markets should the demands of the program be greater than the markets can bear in the short term. EPA agrees that displacement of ethanol from existing markets to satisfy the needs of the RFG program is undesirable, for these and other reasons. Hence, the Agency has designed the renewables program to minimize such displacement. The desire to minimize displacing

ethanol from its existing markets is one of the reasons why EPA is phasing in the renewables program over two years. Nevertheless, there may be some displacement resulting from the program to unique conditions in certain markets. Furthermore, to the extent additional ethanol capacity does not come on-line as quickly as assumed in section D.2., some additional displacement from existing markets may have to occur. However, should these occur, they should be short-lived. Even in the worst case, no displacement should be necessary beyond the 1997 calendar year.

3. Ethanol Production Feedstocks

EPA received several comments regarding the adequacy of ethanol feedstocks to support increased ethanol production. The National Corn Growers Association (NCGA) noted that approximately 90% of ethanol is, at present, produced from corn. NCGA and the Clean Fuels Development Coalition also claimed that increases in per-acre yields would be able to meet the increase in corn demand without increasing the acreage devoted to corn significantly. EPA is unable to verify the accuracy of these projections. However, these comments support EPA's contention that feedstock supplies are adequate to support the renewables program, even if feedstocks other than corn (such as wheat and other crops, landfill methane, cellulosic feedstocks, and agricultural or other wastes) are not used to help meet the increased demand for renewable oxygenates.

EPA also received a comment claiming that ethanol imports would be adequate to make up for any shortfall in domestic ethanol supply. However, EPA's understanding of the current world market for ethanol and of the trade regulations related to fuel ethanol suggest that ethanol imports are unlikely to supply more than a small fraction of the increased ethanol demand resulting from the renewables program.

4. Ethanol Production Capacity

EPA received numerous comments from ethanol producers, trade associations, and industry supporters documenting the current and expected future production capacity for the ethanol industry. Those comments with adequate supporting information have been used by EPA to help support the supply, leadtime, and capacity analysis presented above. Many of the comments were submitted in order to support claims that a phase-in of the full 30 percent requirement was not necessary. Ethanol industry commenters estimated current ethanol production capacity at 1.2 to 1.3 billion gallons, within the range used by EPA in the preceding analysis. Commenters also estimated that as much as 600 million

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gallons of additional annual capacity would be available by 1995, but ethanol industry estimates of the increase in capacity by 1995 were also as small as 200 million gallons.

Ethanol industry commenters did not examine winter-only capacity, however, nor did they provide sufficiently detailed information to support their conclusion that adequate capacity would be available to support the renewables requirement without diverting ethanol from existing markets. Furthermore, ethanol industry commenters did not examine the impact of widespread ETBE production on total oxygenate supply (ETBE production requires conversion of MTBE capacity and consumes the output of ethanol capacity, thereby reducing overall oxygenate capacity). Given these factors, EPA considers the analysis presented above to be more detailed and accurate, in part because it examines start-up dates and production capacities for individual new ethanol production facilities and expansions of existing plants in order to determine available capacity.

EPA also received comments from refiners expressing concern that ethanol production capacity would not be sufficient to supply the needs of the renewable oxygenate program, the oxygenated fuels program, and existing gasohol demand. For example, one commenter noted that the winter ethanol demand resulting from the renewables program would amount to 90% of current production capacity. This commenter also noted that the leadtime required to convert MTBE plants to ETBE production would prevent significant quantities of ETBE (which would help alleviate the pressure on winter ethanol production capacity) from being produced in 1995. On the basis of the analysis presented above, EPA believes that adequate ethanol supplies will exist to meet the needs of the renewable oxygenate program. While EPA has attempted to design the program to minimize the amount of ethanol that would have to be diverted from other markets, EPA nevertheless acknowledges that some such diversion may occur in some markets during the initial years of the renewable oxygenate program. Nevertheless, adequate ethanol supply will exist to fulfill the requirements of the renewable oxygenate program.

5. ETBE Production Capacity

EPA received several comments regarding the leadtime
required to convert MTBE plants to ETBE production. EPA
considers the leadtime estimates from oxygenate producers, who
are most familiar with the regulatory and technological issues
involved, to be the most reliable estimates of the time required
to obtain the necessary permits, perform the appropriate
engineering studies, and complete the construction necessary to
convert MTBE plants to ETBE production. These estimates range
from one to three years and are incorporated in EPA's analysis of
the leadtime involved in expanding ETBE production.

6. Distribution, Storage, and Blending Capacity

EPA also received comments on the implications of the
renewables program for the fuel distribution system. Many of the
comments focused on the increased complexity resulting from the
RFG program and noted that the renewables program would result in
additional complexity. Some commenters noted that the time
required to obtain permits and construct additional distribution
facilities would make it difficult to comply with the full 30
percent renewables requirement in 1995. Others noted that the
additional tankage and blending facilities would increase the
cost of the program; these costs are discussed in section IV.

EPA also received extensive comments from the Ethanol Ad Hoc
Committee regarding the adequacy of existing tankage and blending
facilities to support full implementation of the 30% renewables
requirement in 1995. Based upon comments received during the
development of the RFG program, the Agency also is aware that
existing tankage and blending facilities will be stressed as a
result of the requirements of the RFG program, even without the
added requirements of the renewable oxygenate program. Upon
thorough consideration of the comments received, as well as its
own analysis, EPA has concluded that the existing tankage and
blending facilities cannot support full implementation of the 30%
renewables requirement if met entirely with winter ethanol. The
analysis (presented elsewhere in this section) does indicate,
however, that adequate tankage and blending facilities will be in
place to support a two-year phase-in of the renewable oxygenate
requirements.

The Ethanol Ad Hoc Committee commented, and EPA agrees, that
widespread ETBE availability would reduce the need for additional
distribution, storage, and blending capacity. As discussed
earlier, however, EPA's analysis and comments from ether

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producers indicate that significant amounts of summer ETBE
capacity will not be available prior to 1996 at the earliest.

7.   Phase-In

EPA received many comments from oil companies and trade
associations, auto companies, gasoline marketers, and State
agencies which argued that the renewable oxygenate requirement
should be phased in gradually over time instead of being
implemented at the full 30% level in 1995. Commenters noted that
full implementation in 1995 could result in supply shortages,
price spikes, and other disruptions to the reformulated gasoline
program. Commenters also noted that a significant amount of
ethanol would have to be diverted from existing markets to supply
the full 30% requirement in 1995. Some commenters predicted that
without a phase-in, the increase in ethanol demand would lead to
large price increases. One commenter noted that several States,
notably Minnesota and Wisconsin, were considering mandating 10%
ethanol content in all gasoline sold in their state and pointed
out that such mandates would further reduce the amount of ethanol
available to meet the renewables requirement.

Other commenters claimed that existing distribution,
storage, and blending facilities would not be able to cope with
the demands of a 30% renewables requirement in 1995, particularly
in light of the additional complexity being introduced by the RFG
program. Commenters noted that 6-12 months were required to
obtain permits to build additional storage and blending
facilities and an additional 3 months to construct such
facilities. One State agency commenter noted that some State
permitting agencies may choose to delay (rather than expedite)
permit applications for ethanol storage and blending facilities.
Other commenters noted that they would begin producing RFG in
September of 1994 and argued that there would not be sufficient
time between the signing of the renewables rule and the start-up
of RFG production to make the necessary production, contractual,
and distribution network modifications necessary to cope with the
full 30 percent renewables requirement.

Several different phase-in periods were suggested, ranging
from the 15% in 1995 level included in the renewables program to
a delay of up to three years before implementing the renewables
program. EPA has concluded that the two-year phase-in included
in the renewable oxygenate final rule is both necessary and
appropriate, given the concerns over ethanol supply, distribution
capacity, and blending capacity. This phase-in schedule was
supported by Amoco and Brightstar in their comments on the
December proposal. EPA does not believe a longer phase-in is

necessary, based on the information presented in this section's oxygenate supply analysis.

8.   Other comments

EPA received a comment from the City of Chicago expressing concern that the renewables program would limit ethanol-blended fuels to a market share level below their current 38 percent level in Chicago. The renewables rule, both as proposed and as finalized, does not place an upper limit on the market share for RFG blended with renewable oxygenates. Instead, it places a lower limit on that market share on a nationwide basis for the RFG program.

Appendix I

Data Tables A-1 to A-5

Renewable Oxygenate Demand Under RFG Program

Current Ethanol Use

Maximum Blending Capacity

U.S. Fuel Ethanol Operational Production Capacity

New Plants Under Construction and Current Expansions

Plants in Engineering/Financing Stage

Table A-1

Renewable Oxygenate Demand, Current Ethanol Use, and Maximum Blending Capacity for RFG Covered Areas

State	Nonattainment Area	1990 Population (Thousands)	Fraction of Nat'l Gasoline Use	Winter (197 days) '92 Data; 5% spill-over (MM gals)	1993 Demand Ethanol in RFG (MM gals)	1993 State Ethanol Consumption (MM gals)	1993 N/A Area EtOH Consumption (MM gals)	Summer (168 Days) RFG Demand ('92 Data; 5% spill-over) (MM gals)	1993 Demand Ethanol in RFG (MM gals)	1993 State Ethanol Consumption (MM gals)	1993 N/A Area Ethanol Consumption (MM gals)	Maximum Gasohol Blended in 1993	Monthly Maximum Ethanol Blending Capacity	Winter Maximum Ethanol Blending Capacity
California (Total)		29760.000	11.784			36.640	20.377			12.497	6.950	55695.00	3.097	20.134
	Nonattain. Areas (Total)	16551.000	6.553	4039.973	69.932			3926.587	67.969					
	LA-South Coast Air Basin	13000.000	5.147	3173.201	54.928			3084.142	53.386					
	San Diego	2498.000	0.989	609.743	10.555			592.630	10.258					
	SE Desert Modified AQMA	384.000	0.152	93.731	1.622			91.101	1.577					
	Ventura County	669.000	0.265	163.298	2.827			158.715	2.747					
Connecticut (Total)		3287.000	1.219			8.546	8.546			5.098	5.098	16114.00	1.611	10.474
	Nonattain. Areas (Total)	3287.000	1.219	794.236	13.748			687.495	11.901					
	Greater Connecticut	2466.000	0.914	595.858	10.314			515.778	8.928					
	NY-NJ-Long Island	821.000	0.304	198.378	3.434			171.717	2.972					
Delaware (Total)		666.000	0.305			3.596	3.596			0.000	0.000	10321.00	1.032	6.709
	Nonattain. Areas (Total)	666.000	0.305	193.838	3.355			176.866	3.062					
	Philadel.-Wilm-Trenton	553.000	0.253	160.949	2.786			146.857	2.542					
	Sussex Co.	113.200	0.052	32.947	0.570			30.062	0.520					
District of Columbia	Washington, DC	606.900	0.152	98.678	1.708	2.290	2.290	86.519	1.498	0.075	0.075	6950.000	0.695	4.518
Illinois (Total)		11431.000	3.991			72.246	46.024			66.281	42.223	132444.0	8.437	54.842
	Chicago-Gary-Lake County	7282.000	2.542	1674.444	28.985			1415.985	24.511					
Indiana (Total)		5544.000	2.377			29.055	3.171			24.220	2.643	55111.00	0.601	3.909
	Chicago-Gary-Lake County	605.000	0.259	166.812	2.888			148.552	2.571					
Kentucky (Total)		3685.000	1.649			18.734	5.231			12.397	3.462	49750.00	1.389	9.030
	Nonattain. Areas (Total)	1029.000	0.461	296.370	5.130			263.547	4.562					
	Cincinatti-Hamilton	283.000	0.127	81.509	1.411			72.482	1.255					
	Louisville	746.000	0.334	214.861	3.719			191.065	3.307					
Maine (Total)		1228.000	0.529			0.000	0.000			0.000	0.000	0.000	0.000	0.000
	Nonattain. Areas (Total)	808.100	0.348	217.066	3.757			206.150	3.568					
	Hancock & Waldo	79.000	0.034	21.220	0.367			20.153	0.349					
	Knox & Lincoln Co.	66.700	0.029	17.916	0.310			17.015	0.295					
	Lewiston-Auburn	221.200	0.095	59.417	1.029			56.429	0.977					
	Portland	441.200	0.190	118.512	2.051			112.552	1.948					

Area													
Maryland (Total)	4781.000	1.837			1.625	1.448			0.325	0.290	6500.000	0.579	3.764
Nonattain. Areas (Total)	4259.800	1.637	1069.491	18.513			920.002	15.925					
Baltimore	2348.000	0.902	589.503	10.204			507.105	8.778					
Kent & Queen Anne's Co.	51.800	0.020	13.005	0.225			11.187	0.194					
Philadel.-Wilm-Trenton	71.000	0.027	17.826	0.309			15.334	0.265					
Washington	1789.000	0.687	449.157	7.775			386.376	6.688					
Massachusetts (Total)	6016.000	2.084			0.001	0.001			0.000	0.000	0.000	0.000	0.000
Nonattain. Areas (Total)	6016.400	2.084	1346.915	23.315			1186.981	20.547					
Boston-Lawrence	5204.000	1.803	1165.039	20.167			1026.701	17.772					
Springfield	812.400	0.281	181.875	3.148			160.279	2.774					
New Hampshire (Total)	1109.000	0.456			0.000	0.000			0.000	0.000	0.000	0.000	0.000
Nonattain. Areas (Total)	702.000	0.289	184.819	3.199			165.935	2.872					
Boston-Lawrence	297.000	0.122	78.193	1.354			70.203	1.215					
Manchester	222.000	0.091	58.447	1.012			52.475	0.908					
Portsmouth-Dover	183.000	0.075	48.179	0.834			43.257	0.749					
New Jersey (Total)	7730.000	2.911			8.311	8.311			5.534	5.534	15221.00	1.522	9.894
Nonattain. Areas (Total)	7730.400	2.911	1899.108	32.874			1639.462	28.379					
Allentown-Bethlehem	92.000	0.035	22.601	0.391			19.511	0.338					
Atlantic City	319.400	0.120	78.466	1.358			67.738	1.173					
NY-N. NJ-Long Island	5662.000	2.132	1390.969	24.078			1200.796	20.786					
Philadel.-Wilm-Trenton	1657.000	0.624	407.071	7.046			351.416	6.083					
New York (Total)	17990.000	4.883			44.994	34.577			28.804	22.135	119645.0	9.194	59.763
Nonattain. Areas (Total)	13824.800	3.752	2498.515	43.249			2063.069	35.712					
Albany-Skenectady	874.300	0.237	158.010	2.735			130.471	2.258					
Buffalo-Niagara Falls	1189.300	0.323	214.939	3.721			177.479	3.072					
Essex Co.	37.200	0.010	6.723	0.116			5.551	0.096					
NY-N. NJ-Long Island	11464.000	3.112	2071.855	35.864			1710.767	29.613					
Poughkeepsi	260.000	0.071	46.989	0.813			38.800	0.672					
Pennsylvania (Total)	11882.000	4.061			29.225	24.747			8.152	6.903	68221.00	5.777	37.549
Nonattain. Areas (Total)	10061.400	3.439	2232.344	38.642			1948.182	33.723					
Allentown-Bethlehem	595.000	0.203	132.014	2.285			115.209	1.994					
Altoona	131.000	0.045	29.065	0.503			25.365	0.439					
Scranton-Wilkes Barre	734.100	0.251	162.876	2.819			142.143	2.461					
Erie	276.000	0.094	61.237	1.060			53.442	0.925					
Harrisburg-Lebanon	588.000	0.201	130.461	2.258			113.854	1.971					
Johnstown	241.200	0.082	53.516	0.926			46.703	0.808					
Lancaster	423.000	0.145	93.852	1.625			81.905	1.418					
Philadel.-Wilm-Trenton	3729.000	1.275	827.361	14.322			722.044	12.499					
Pittsburgh	2468.200	0.844	547.625	9.479			477.916	8.273					
Reading	337.000	0.115	74.771	1.294			65.253	1.130					
York	417.900	0.143	92.720	1.605			80.918	1.401					
Youngstown-Warren	121.000	0.041	26.847	0.465			23.429	0.406					

Rhode Island (Total)	1003.000	0.330			0.000	0.000			0.000	0.000	0.000	0.000	0.000
Providence	1003.500	0.331	216.673	3.751			185.212	3.206					
Texas (Total)	16987.000	7.511			17.721	7.607			11.946	5.128	32675.00	1.403	9.117
Nonattain. Areas (Total)	7292.000	3.224	2009.273	34.781			1910.184	33.065					
Dallas-Fort Worth	3561.000	1.575	981.215	16.985			932.826	16.147					
Houst.-Galvest.-Brazoria	3731.000	1.650	1028.058	17.796			977.358	16.918					
Virginia (Total)	6187.000	2.672			12.602	7.468			4.765	2.824	49668.00	2.943	19.132
Nonattain. Areas (Total)	3666.400	1.584	1014.315	17.558			910.742	15.765					
Norfolk-Virginia Beach	1365.900	0.590	377.878	6.541			339.293	5.873					
Richmond-Petersburg	739.100	0.319	204.473	3.539			183.594	3.178					
Smyth Co.	32.400	0.014	8.964	0.155			8.048	0.139					
Washington, DC	1529.000	0.660	423.000	7.322			379.807	6.574					
Wisconsin (Total)	4892.000	1.875			9.253	3.715			5.279	2.119	67770.00	2.721	17.685
Nonattain. Areas (Total)	1964.000	0.753	475.967	8.239			438.943	7.598					
Milwaukee-Racine	1735.000	0.665	420.470	7.278			387.762	6.712					
Door	26.000	0.010	6.301	0.109			5.811	0.101					
Kewaunee	19.000	0.007	4.605	0.080			4.246	0.074					
Manitowoc	80.000	0.031	19.388	0.336			17.880	0.309					
Sheboygan	104.000	0.040	25.204	0.436			23.243	0.402					
Nonattainment Total	87126.700	31.843	20373.340	353.623	294.838	177.108	18280.411	316.434	185.373	105.384		41.003	266.520

Table A-2: U.S. Fuel Ethanol Operational Production Capacity

Plant Name	Plant Location	Annual Operational Capacity MM gals/yr	Plant Name	Plant Location	Annual Operational Capacity MM gals/yr
ADM	Decatur, IL	330	Grain Processing	Muscatine, IA	10
ADM	Peoria, IL	200	Reeve Ag-Energy	Garden City, KS	7.5
ADM	Cedar Rapids, IA	170	Manildra Energy	Hamburg, IA	6
ADM	Clinton, IA	140	Midwest Grain	Pekin, IL	12
Pekin Energy	Pekin, IL	100	Heartland Grain	Aberdeen, SD	5
New Energy Co.	South Bend, IN	75	Morris Ag-Energy	Morris, MN	4.5
South Point Ethanol	South Point, OH	65	J.R. Simplot	Caldwell, ID	4
A.E. Stanley	Loudon, TN	40	Georgia Pacific	Bellingham, WA	3.5
Minnesota Corn Proc	Marshall, MN	32	J.R. Simplot	Burly, ID	3
Cargill	Eddyville, IA	30	Golden Cheese	Corona, CA	2.6
Minnesota Corn Proc	Columbus, NE	30	Alcoteen Inc.	Ringling, MT	2
Chief Ethanol Fuels	Hastings, NE	30	Parallel Products	Cucamonga, CA	2
High Plains Corp	Colwich, KS	20.9	Kraft Inc.	Melrose, MN	1.2
The Hubinger Co.	Keokuk, IA	18	Minnesota Clean Fuels	Dundas, MN	1.2
ADM	Walhalla, ND	16	Broin Enterprises	Scotland, SD	1
Alchem Limited	Grafton, ND	12	Dairymen's Coop.	Tulare, CA	0.7
Giant Refining	Portales, NM	12	Pabst Brewing Co.	Olympia, WA	0.7
Midwest Grain	Pekin, IL	12	ESE Alcohol Inc.	Leoti, KS	0.5
			Vienna Correctional	Vienna, IL	0.5
			Total:		1393

SOURCE: RENEWABLE FUELS ASSOCIATION

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Table A-3: New Ethanol Production Capacity: Plants Under Construction

Plant Name	Annual Operational Capacity MM gals/yr	Stated Start-up Date	1995 Ethanol Wintertime Production	1996 Ethanol Wintertime Production
Cargill	80	1st Quarter 1995	23	43
Midwest Grain	60	1st Quarter 1995	18	33
High Plains	50	2nd Quarter 1995	15	27
Nebraska Nutrients	15	2nd Quarter 1994	8	8
Archer Daniels	11	4th Quarter 1994	6	6
Heartland Corn Prod.	10	4th Quarter 1995	0	5
Minnesota Corn Proc.	10	1st Quarter 1995	3	5
Total:	236		73	127

Table A-4: New Ethanol Production Capacity: Existing Plant Expansions

Plant Name	Annual Operational Capacity MM gals/yr	Expected Start-up Date	1995 Ethanol Wintertime Production	1996 Ethanol Wintertime Production
South Point	10	Mid 1995	3	5
A.E. Stanley	20	Mid 1995	6	11
Chief Ethanol	15	Mid 1995	4	8
The Hubinger	11	Mid 1995	3	6
Giant Refining	2.5	Mid 1995	1	1
Morris Ag-Energy	10.5	Mid 1995	3	6
Total:	69.0		20	37

Table A-5: New Ethanol Production Capacity: Plants in Engineering/Financing Stage

Plant Name	Annual Operational Capacity MM gals/yr	Stated or Expected Start-up Date	1996 Ethanol Wintertime Production
North Carolina Ethanol	60	1996	18
AGP	30	1996	9
Grain Processing Corp.	30	1996	9
Iowa Corn Millers	28	1996	8
American Maize-Products	25	1996	7
Great Plains Ingredient	20	1996	6
Dawson Project	20	1996	6
Oregon Ethanol	20	1996	6
Appleton Project	15	1996	4
ARKENOL	15	1996	4
Corn Plus	15	1996	4
Quadrex	10	1996	3
Quadrex Corp./ Bionel	10	1996	3
ARKENOL	6	1996	2
Total:	304		89

SOURCE: RENEWABLE FUELS ASSOCIATION

II. Energy Impacts

     In the Technical Support Document (TSD) developed in support
of the NPRM, EPA estimated both the energy and crude oil impacts
associated with the proposed renewable oxygenate requirement. In
both cases, EPA used an analysis performed by the Department of
Energy (DOE) as the primary source of its estimates.[19] The
reader is referred to the TSD for the details of that analysis.
In response to the proposal, EPA received comments on its
estimated energy and crude oil impacts, as well as on the impact
of the proposal on vehicular fuel economy. These comments are
evaluated below, along with updated estimates of the impacts of
the final rule on national fossil energy consumption, vehicular
fuel economy, and national crude oil consumption.

A.   <u>Fossil Energy Impacts</u>

1.   Basis for the Proposal

     The DOE analysis used as the basis for estimating the fossil
energy benefits of the proposed rule evaluated total energy
consumption (including solar energy contained in corn) and only
addressed summer, VOC-controlled reformulated gasolines (RFGs).
Thus, EPA made two adjustments in using the results of the DOE
analysis. First, the solar energy contained in the corn used to
produce ethanol was deducted. DOE had performed a total energy
analysis which logically included the solar energy absorbed by
the corn. However, solar energy is abundant, and essentially
free. Therefore the term renewable (i.e., inexhaustible) is
usually applied to those processes which convert solar energy
into other more useful forms of energy. EPA does not believe
that Congress, when it referred to "energy requirements" in
section 211(k)(1) of the Clean Air Act, intended to direct EPA to
conserve the use of solar energy. Rather, the history of energy
conservation in the U.S. and the focus of all energy conservation
legislation has been on fossil fuels, or specific types of fossil
fuels, such as crude oil. Therefore, the solar energy component
was deducted from the analysis.

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[19] Singh, Margaret and Barry McNutt, Argonne National
Laboratory and U.S. Department of Energy, respectively, "Energy
and Oil Input Requirements for the Production of Reformulated
Gasolines," May 1993.

Second, the energy required to reduce the RVP of ethanol-containing RFG also was deducted. DOE had performed its analysis in the context of EPA's renewable oxygenate standards which were proposed on February 26, 1993 (58 FR 11722). Under that program, ethanol blends would have received credit in the summer when RVP and VOC emissions were restricted by the Simple and Complex Models. Therefore, DOE included the energy requirements of lowering the RVP of ethanol blends to MTBE blend levels. This was not necessary under the renewable oxygenates program proposed in February 1994. Therefore, the RVP-related energy was deducted.

Since the proposed rule was published, DOE has updated their analysis to make it specific to the proposed renewable oxygenate requirement.[20,21] In their June 1994 analysis, DOE specifically addressed the two adjustments EPA made for the proposal, and expanded the evaluation to address other oxygenate combinations which could be used to comply with the proposed renewable oxygenate requirement. As the adjustments made by EPA to the original DOE analysis were approximations, the updated DOE analysis will be used as the basis here for evaluating comments and any further revisions to the fossil energy impacts associated with the final rule.

Selected results of the June 1994 DOE analysis are shown in Table II-1 below, along with those contained in the TSD for the proposal. Shown are fossil energy estimates for MTBE blends (summer and winter), an ETBE blend (summer only) and an ethanol blend (winter only). ETBE blends are only shown as being used in the summer, while ethanol blends are used in the winter. Though ETBE blends are credited as being renewable oxygenates year-round, ETBE blends are projected to be more expensive than ethanol blends. Ethanol blends, however, are not credited as being renewable oxygenates in the summer, because of their commingling effect on the RVP of the RFG pool and the resultant impact on VOC emissions. Thus, it is generally expected that the majority of renewable oxygenate in the summer will be ETBE, while ethanol blends will dominate in the winter.

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[20] Singh, Margaret, "Energy Requirements and CO2-Equivalent Emissions of RFG," Argonne National Laboratory, March 17, 1994 (Draft).

[21] Singh, Margaret, "Analysis Memorandum: Energy Requirements and CO2-Equivalent Emissions of RFG," Argonne National Laboratory, June 6, 1994.

**Table II-1: Total Fossil Energy Consumption
of Summer and Winter Gasolines**

Oxygenate (Source)	Initial Analysis (for NPRM)		Final Analysis	
	Btu per gallon (Btu/gal)	Change Relative to MTBE	Btu/gal	Change Relative to MTBE
Summer				
Conventional Gasoline	129,382	-0.5%	129,586	-1.3%
MTBE (natural gas)	130,087	---	131,297	---
ETBE				
(From New EtOH)	128,065	-1.6%	129,004	-1.7%
(From Existing EtOH)	128,065	-1.6%	130,251	-0.8%
Winter				
Conventional Gasoline	127,665	+0.2%	127,868	-0.6%
MTBE (natural gas)	130,087	---	128,629	---
Ethanol				
(New EtOH)	125,967	-3.2%	125,741	-2.2%
(Existing EtOH)	125,967	-3.2%	126,915	-1.3%

As can be seen from Table II-1, DOE's more recent analysis evaluated the use of two types of ethanol. One type was ethanol which is already being used in conventional gasoline ("Existing EtOH"). The other type was ethanol produced over and above that which would have been produced without this program ("New EtOH"). The latter ethanol includes that produced in current facilities operating at higher capacity, as well as ethanol from new facilities.

The source of the ethanol affects the fuel components that are displaced by the renewable oxygenate mandate. When ethanol is produced incrementally for this program, conventional gasoline is assumed to be unaffected by the renewable oxygenate

requirement. The new ethanol and some additional hydrocarbon blendstock replaces MTBE in reformulated gasoline. When currently produced ethanol is shifted from existing markets to reformulated gasoline, ethanol production does not change. On the other hand, the renewable oxygenate requirement is still reducing the amount of MTBE produced and increasing the amount of hydrocarbon blendstock for use in both RFG and conventional gasoline.

As shown in Table II-1, the revised DOE estimates of the energy benefits of ETBE and ethanol blends assuming new ethanol use are very similar to EPA's estimates developed in support of the proposal. The revised DOE estimates of the energy benefits of ETBE and ethanol blends produced using current ethanol are somewhat smaller, showing generally about half the energy benefits relative to MTBE blends compared to EPA's estimates. Still, in all cases summertime ETBE and wintertime ethanol blends appear to provide energy benefits relative to MTBE use.

In the "existing ethanol" scenarios, the primary benefit is due to the replacement of MTBE (and thus, methanol) by crude oil-based gasoline. Since methanol production is the least fossil energy efficient process among those being affected, a net energy improvement results.

Under the new ethanol scenario, the energy savings increase further due to the fact that ethanol production is more than 100% efficient because of its use of solar energy. Under this scenario, not only is fossil energy consumption reduced relative to non-renewable reformulated gasoline, but also relative to conventional fuel.

2.   Comments on the Proposal

EPA received a number of comments on the energy benefits developed in support of the proposal. These are categorized and summarized below.

a.   Current Ethanol Farming and Production Processes

A number of commenters cited a study by the Institute for
Local Self Reliance (ILSR) which claimed a more positive energy
balance for ethanol production than that used by DOE. The ILSR
study found that the ethanol produced from the average ethanol
facility today contained 25,139 Btu/gal more than the fossil
energy consumed in production (only 0.67 Btu needed to produce
1.0 Btu of ethanol). This is in contrast to DOE's estimate that
ethanol production produces 15,000 Btu/gal (of ethanol) more than
that consumed in production (0.80 Btu needed to produce 1.0 Btu
of ethanol). (The source of the differences will be discussed in
greater detail in the next section.) They also projected that
future state-of-the-art plants will yield more than 50,000
Btu/gal ethanol than that consumed in production (only 0.33 Btu
needed to produce 1.0 Btu of ethanol). The ILSR study also
projected that the use of waste/biomass would increase ethanol's
positive energy balance further.

     The U.S. Department of Agriculture (USDA) performed a
similar study to that performed by ILSR and submitted it as
support for greater energy savings being associated with ethanol
production and use than that projected by EPA in the proposal.
The USDA study found that ethanol production and use consumed
only 28,150-37,000 Btu of fossil fuel and 0.974-1.2 kilowatt-
hours of electricity per gallon of ethanol, depending on whether
the plant was a wet or dry mill. In both cases, the best
commercially proven technology was assumed to be used. USDA also
cited significant reductions in farm energy and fertilizer use
between 1978 and 1989 as evidence that even higher efficiencies
can be expected for ethanol use in the future. USDA stated that
the index of farm efficiency (agricultural output per energy
input) decreased from 108 to 60 between 1978 and 1989 mostly due
to the increased use of diesel farm equipment and that farm
productivity increased as from an index of 92 in 1974 to 185 in
1990.

     The Clean Fuels Development Coalition (CFDC) stated that
the energy gain from ethanol ranges from 0.2% to 54% without
considering the value of agricultural co-products, and ranges
from 33% to 245% considering co-products, based on the results of
the ILSR study. Furthermore, CFDC stated that DOE, USDA and the
Congressional Research Service have estimated a 2% annual
improvement in ethanol industry efficiency over the past decade
and that this can be expected to continue. CFDC also said that
feedstock production requirements can vary widely, from 47,000
Btu/gal for the most inefficient farming methods to 16,570
Btu/gal for a cellulose-based feedstock.

The American Petroleum Institute (API) stated that the DOE analysis should utilize the yields, energy requirements, etc., of the bottom 25% of the nation's farmland, since the incremental corn production will utilize such land.

The Ad Hoc Committee on Ethanol (AHCE) made a number of comments pertaining to the energy analysis. First, they stated that the DOE analysis on which the EPA proposal was based must be adjusted to not count the solar energy in the ethanol and not include the energy needed to adjust the RVP of gasoline for ethanol blending. They estimated that these two corrections would give ETBE a 2886 Btu/gal advantage over MTBE and give ethanol a 2008 Btu/gal advantage.

Second, they stated that the energy required to produce and process corn should be the marginal energy, not the industry average. They stated that new ethanol capacity coming on line would incorporate the latest, most efficient technology such as membrane separation, continuous fermentation, immobilized yeast, microfiltration, pervaporation, and hemicellulose conversion. New wet milling plants would use less than 2.0 kilowatt hours per gallon and less than 33 lbs of steam per gallon of steam consumption. They stated that conservative adjustments to DOE figures to adjust them to a marginal analysis would reduce energy consumption for ethanol and ETBE by 50 Btu/gal, and assuming state of the art technology would reduce energy consumption by 500 BTU/gal.

Third, they stated that corn surpluses will be very large in the future and that most of the additional corn needed to supply the ethanol for the renewable oxygenate program will come from surplus corn. Thus, they concluded, the energy needed to farm the corn should not be considered in this analysis.

Fourth, AHCE stated that the ethanol byproducts credit in the DOE study is far too conservative. They recommend use of ILSR's larger byproduct credits.

Finally, based on all the above adjustments, AHCE stated that assuming that 70% of U.S. gasoline will be reformulated and that 30% of that would be oxygenated with ethanol, the annual energy savings would be 62 - 104 trillion Btu. AHCE indicated that this energy savings corresponded to 17.7 million barrels of crude oil and that it would take four years for that amount of oil to be added to the Strategic Petroleum Reserve.

The Illinois Corn Growers Association stated that research projects are expected to reduce the time of processing corn from 4 days to less than 24 hours.

The Minnesota Ethanol Committee stated that ethanol production requires 66,846 btu/gal, but ethanol deserves a 32,700 btu/gal credit for the byproducts. They stated that the net energy output for ethanol is 41,850 btu/gal.

The Sierra Club stated that the proposal failed to establish that there would actually be a fossil fuel benefit, and further that EPA's calculations were too subjective and seemed to be too favorable for ethanol.

b.   Future Ethanol Production Processes

Sunthetic Energy of America stated that their patented multiple oxygenates process (MOP) significantly improves the overall energy balance of producing renewable oxygenates. For example, they stated that the MOP process produces a gallon of ethanol using 34,000 Btu of input energy (a net production of 41,000 Btu/gal ethanol, or 0.45 Btu to produce 1.0 Btu of ethanol).

The National Renewable Energy Laboratory stated that they were developing advanced cellulose-based ethanol production technology which would dramatically reduce the energy required to produce ethanol. They also stated that currently their technology produces 5 units of energy in the form of ethanol and electricity for every 1 unit of fossil energy input. The cost of this ethanol is too high to be competitive with corn-based ethanol at this time. However, they believed that with aggressive research funding, the cost of ethanol produced via such processes could be reduced to be competitive with gasoline produced from $25 per barrel crude oil, without any tax subsidies for the ethanol production.

The American Biofuels Association commented that the production of renewable fuels can be made more efficient by the use of low value biomass such as agricultural waste, garden and yard trimmings, municipal waste, etc., for renewable fuel production.

c.   Hydrocarbon Processing Energy

      Arco Chemical Company performed their own adjustment of the
original DOE analysis similar to that performed by EPA. ARCO
removed the solar energy implicitly contained in the ethanol and
for ethanol blends and removed the energy needed to control the
RVP increase associated with ethanol blending. They found that
summertime ETBE and wintertime ethanol blends reduced total
fossil energy consumption by 1.4% and 0.1% relative to MTBE
blends. They also suggested that EPA grant ETBE blends more
credit towards compliance with the renewable oxygenate
requirement based on its greater energy and environmental
benefits.

      API commented that DOE's study appeared to assume that the
hydrocarbon portion of the various oxygenate blends would be the
same, since they all have the same energy requirement. API
stated that this would not be the case, however, since ETBE
blended with the same hydrocarbon blendstock would produce 7%
less toxics reduction than an MTBE blend. Further processing of
the ETBE blend would be necessary to ensure it met the required
toxics performance.

3.   Analysis of Comments

a.   Current Ethanol Farming and Production Processes

      This section will begin with an examination of the ILSR
study, followed by that of the USDA study. Analysis of more
specific comments will follow.

      It is very difficult to assess the accuracy of the cited
ILSR study and its higher ethanol production efficiencies, . The
report was published in December 1992, but does not appear to
have been peer reviewed or evaluated in detail by any party
having significant expertise in this area. Its projections of
the energy needed to produce ethanol are well below those
estimated by Mark A. DeLuchi, the source of DOE's figures.
DeLuchi's study was extensively reviewed by a number of parties
prior to publication. DeLuchi's estimates are also more in line
with the estimates of Marland and Turhollow of Oak Ridge National
Laboratory (also referenced in the June 1994 DOE study), the
previously widely accepted source of ethanol production
efficiencies. In addition, the ILSR study appears to take
figures from a wide variety of sources to estimate the energy use
for ethanol production for the average plant in the U.S. Some
have references, but others, such as the average farming-related
fuel use, do not. Also, there is an "other" category for farm

energy inputs which represents over 35% of the total which is not referenced nor explained sufficiently in the text.

The energy assigned to agricultural byproducts associated with ethanol production (e.g., corn oil, corn gluten meal, 21% protein feed and carbon dioxide) is very important to any ethanol energy balance due to the significant amount of byproducts produced. ILSR assigns energy to these products for the average ethanol plant using the "replacement method" which estimates the energy needed to produce these products from alternative sources. While this is probably the most appropriate method to use in theory, ILSR implements this approach in a questionable and unverifiable fashion. ILSR chose soybean oil as the replacement for corn oil, barley-derived high protein feed as the replacement for corn-derived high protein feed, and other generic fermentation processes as the alternative source of carbon dioxide. No alternative source is cited for the corn gluten meal, but a replacement energy value is shown. None of these replacement products can be produced alone; all are themselves byproducts or coproducts of the processing of other grains. Therefore, assigning them energy values involves the same difficulties as the original problem of assigning energy values to the corn processing byproducts. Also, no methodology or references are provided for the sources of these replacement energy values.

Another problem with ILSR's choice of replacement products is that expanded corn farming and ethanol production cannot replace soybean oil, high protein barley feed and carbon dioxide production simultaneously. The commonly accepted belief is that expanded corn farming to produce ethanol will primarily decrease soybean farming, thus decreasing high protein soy meal and soybean oil. The energy savings associated with decreased soybean farming can be estimated much more easily and confidently than the approach taken by ILSR. This approach to valuing byproducts is also much more realistic, since it represents what is actually likely to occur.

Finally, ILSR takes an energy credit for carbon dioxide produced during fermentation. While some carbon dioxide (which is a greenhouse gas) produced today is used productively, much is simply emitted to the atmosphere. The situation being evaluated in this rule is one of vastly increased ethanol production over current levels. ILSR presents no evidence of a commercial demand for any additional carbon dioxide, let alone the large amount associated with this rule. Thus, no energy credit should be provided for this byproduct.

Regarding ILSR's projection of "Best Existing" plant energy usage, ILSR appears to select the best current figures from each part of the ethanol production process and combine them without any regard for the appropriateness of the combination. Thus, ILSR's estimates often combine figures which could be applicable, at best, to only a portion of the nation's corn harvest or ethanol production. Corn yields per acre could come from Iowa, fertilizer usage could be taken from South Dakota, tractor fuel usage might apply to Illinois, etc., without any analysis demonstrating that corn yields in the rest of the country could be increased to those of Iowa's farms with the fertilizer usage of South Dakota's farms, etc. The same holds true for the various factors affected the efficiency of ethanol production, such as transportation of the raw material and products, size of the ethanol plant, etc. Thus, ILSR's Best Existing figures are unlikely to apply to any ethanol actually produced in the U.S. and certainly do not apply to a large increase in ethanol production, such as that envisioned for this program.

For example, the requirement for nitrogen fertilizer was reduced from an average use of 127 pounds per acre to 71 pounds per acre. The latter figure came from current usage in South Dakota, the state with the lowest current nitrogen fertilizer usage. This low current fertilizer usage may well be due to soil conditions, climate, and other factors very specific to South Dakota. No explanation was given for why this is a reasonable assumption for the rest of the U.S., but it seems unlikely that the fertilizer usage in South Dakota would be adequate to maintain corn yields in all the other areas where new corn will be grown to meet the requirements of the renewable oxygenate program.

Regarding the applicability of the ILSR results in support of this rule, as suggested by the commenters citing the ILSR study, one would also have to demonstrate that this low fertilizer usage could and would occur throughout for all incremental ethanol farming resulting from this rule. Clearly, no one expects all the incremental corn production to occur in South Dakota alone. Thus, the figures for the Best Existing plant from the ILSR report are not an adequate basis to support this rule.

Likewise, serious problems appear to be present in ILSR's State of the Art projections. Regarding the energy needs of corn farming, dramatic (over 67%) reductions in fertilizer usage are projected based on studies which either show that various farms use differing amounts of fertilizer or which project that reductions are possible if farmers use (unspecified) alternative

growing techniques. Again, the relationship between fertilizer usage, soil quality, climate, and corn production is unknown and not evaluated in the ILSR study. Thus, one cannot simply project that every corn farmer could lower fertilizer usage to the lowest current level and still maintain production. Also, a Missouri study is cited as projecting that a 40% reduction in nitrogen fertilizer usage would be possible with the unspecified alternative growing techniques mentioned above. ILSR reduces nitrogen fertilizer usage by 46% (not 40%) from the low current South Dakota figure mentioned above. The Missouri study may or may not have a bearing on fertilizer usage in South Dakota, but this issue is not even addressed in the ILSR study.

In addition, in numerous areas insufficient detail was provided in the report to fully evaluate its conclusions. Thus, while many of the individual figures included in the ILSR study may be accurate and appropriate, the above mentioned problems, as well as numerous others, and the overall lack of detail make the results and conclusions of the study questionable and thus, EPA is not relying on it as support for this rule.

Regarding the USDA study of ethanol production, USDA stated that the best currently available ethanol production technology is 125% efficient if wet mill-based and 108% efficient if based on dry mills. DOE's energy balance showed that they projected the overall ethanol production process to be 118% efficient, within the range estimated by USDA and not far from the higher end of the range. Despite this, USDA claimed that DOE significantly overestimated the energy associated with ethanol production, implicitly arguing that DOE should have used an even higher efficiency level. Also, DOE's own analysis of the USDA figures showed that USDA's projections resulted in about 25% less fossil energy needed to produce ethanol than that projected by DOE.[22] The DOE energy balance based on the USDA figures (Table 7 of the June 1994 DOE report) shows an overall efficiency of 149% for ethanol production. Thus, the detailed USDA energy estimates and their projected overall energy savings appear to be based on much more efficient processes than they indicated. The USDA analysis appears to assume a wet mill technology that is more than 150% efficient and a dry mill technology that is about 140% efficient. This is not consistent with USDA's prior statement regarding efficiency.

DOE found that the differences between the two studies were in the energy consumed in fertilizer production and use, and the

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[22] Singh, June 6, 1994.

efficiency of farming, corn transport, and corn-to-ethanol conversion. Some of these differences can be attributed to the fact that the DOE estimates of corn-to-ethanol conversion were based on the average current ethanol, while the USDA figures were based on combining the most efficient technology from today's existing plants. The USDA estimates for the efficiency of corn farming represent the official U.S. government estimates since they are based on the annual Farm Cost and Return Survey conducted by USDA.[23]

As essentially all commenters agree that ethanol technology has advanced considerably over the past 15 years, it appears reasonable to expect that new ethanol plants would tend to incorporate better technology than the current average plant. Thus, the DOE estimates are likely conservative in this area. However, there are also reasons why every new plant is unlikely to incorporate the most efficient piece of equipment found anywhere in the U.S. today. More efficient technology usually comes at a cost, either in terms of higher capital investment or operating cost or increased risk (e.g., less proven long term performance, etc.) Each ethanol producer will have its own available sources of power, as well as projected future energy costs, both of which will strongly affect investment decisions. Various ethanol producers will also have differing financial capabilities and some may not have the financial ability to purchase every technology advancement. Investment decisions are usually made to maximize profits for a given investment and not explicitly to minimize energy use. Therefore, achievement of the latter goal cannot be assumed to occur naturally.

Finally, plant size tends to play a major role in determining overall energy efficiency, with efficiency tending to increase with increased ethanol capacity. Smaller ethanol plants are still being built based on local subsidies and the federal tax credit for plants smaller than 30 million gallons per year. These plants generally cannot produce the same overall energy efficiencies as the very large units. As discussed in Appendix I to Section I of this RIA, most of the new ethanol capacity coming on-line in the next two years will be from smaller plants. While the promulgation of this program will likely encourage even more new capacity, it is not clear whether these new plants will be small or large, particularly given the tax incentives granted for small plants. Thus, plant size could be a major factor in affecting the average efficiency of new ethanol production.

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[23] 1991 Farm Cost and Return Survey, USDA Economic Research Service.

Overall, the efficiency of new ethanol plants could very well be near that assumed by DOE and not as high as that projected by USDA.

However, other differences exist between the two studies, such as fertilizer use per acre and the energy required to produce the various types of fertilizer, occur which should produce similar results. For example, USDA projected that it takes 22,160, 4176, and 1243 Btu/pound to produce nitrogen, phosphate, and potash fertilizers, respectively, based on a study by the Fertilizer Institute. DOE used generally higher figures of 25,000, 3000, and 3000 Btu/pound, respectively. Nitrogen-related energy requirements dominate the results of both analyses and the USDA figures are just under 15% lower than those of DOE. Also, USDA's nitrogen fertilizer usage per acre appears to be more than a factor of two lower than DOE's estimate. The cause of this discrepancy, however, is not clear, as both studies cite independent sources for their figures. However, the USDA estimates may be more reliable since they represent the official U.S. government estimates.[24]

One other difference between the two studies applies to the energy credits taken for corn-related agricultural byproducts. The DOE study used the replacement method described above, while USDA took no credit *per se*, but instead excluded any energy used specifically to process the byproducts. USDA stated that this is the more conservative method, but this in fact is not clear. Given the wet nature of the byproducts from wet milling, significant energy must be invested in their drying and processing for eventual use. This energy does not necessarily need to be less than that needed to produce, for example, soybean meal as a replacement. Since the information supplied by USDA does not allow for a clear determination of the energy so excluded, it is not clear whether such an assumption is more conservative than DOE's replacement method or not.

While not accepting the USDA figures, DOE evaluated the potential of various ethanol production efficiencies to affect the energy savings resulting from the renewable oxygenate program. They used the USDA estimates to represent a higher efficiency process, while they utilized earlier estimates by Ho[25]

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[24] 1991 Farm Cost and Return Survey, USDA Economic Research Service.

[25] Ho, S.P., "Global Warming Impact of Ethanol Versus Gasoline," Presented at 1989 National Conference on "Clean Air

to represent lower efficiency processes. The effect of either raising or lowering the efficiency of ethanol production was about 0.2% in each direction. The specific results of this sensitivity analysis will be presented below in Section II.A.4., along with the final energy impacts of this rule.

One inadequacy apparently present in all the above studies was raised by API in their comments and acknowledged as a source of uncertainty by DOE in its June 1994 report. It pertains to the specific farmland likely to be utilized by the additional corn farming associated with this rule. The above studies use average or better than average farmland (and its associated energy requirements) in their calculations. However, it is not clear that the incremental acreage to be planted with corn would be average farmland. This would appear to depend strongly on whether it use was diverted from another crop with similar soil preferences or whether the land was marginal and not currently being cultivated. It is not possible to accurately project this feature of the program. However, it remains a source of significant uncertainty and probably has a larger effect on the overall energy efficiency of ethanol production than the differences between the USDA and Ho analyses (the low and high ends of the range calculated by DOE). Thus, this factor likely counteracts any potential downward bias in DOE's use of the efficiency for the average ethanol plant in its analysis and could make DOE's overall estimate of ethanol production efficiency somewhat optimistic.

Based on USDA and CFDC comments, the energy efficiency of corn farming has steadily increased between 1978 and 1989. However, as mentioned by USDA, the reduction in farm fuel consumption was primarily due to the conversion of farm equipment from gasoline to diesel engines. This conversion began in earnest in the 1970's and should have been essentially complete by 1989. Thus, further improvements in this area are likely to be much smaller than in previous years. While corn yields per acre and fertilizer use per acre have been rising, total cultivated acreage has also been falling. This means that the improvements seen could be at least partly due to the idling of the least efficient farmland which could have to be reactivated to produce the ethanol needed for this program. Thus, there is significant doubt that these trends will continue, particularly if applied to incremental acreage used to provide new ethanol for

Issues and America's Motor Fuel Business", Washington, D.C., October 1989.

this program. Therefore, an inadequate basis exists for the use of continued farming improvements in support of this rule.

According to the CFDC comments, the efficiency of ethanol production has steadily increased over the past few years. However, USDA's study described above already factored this in.

The suggested adjustments to the DOE figures made by AHCE for the solar energy contained in ethanol and the energy involved in reducing the RVP of ethanol blends are already included in DOE's revised analysis. Regarding AHCE's projections of increased agricultural and ethanol production efficiencies, many of these were based on the ILSR study. The others were based on USDA projections of increased yields of corn per acre or general expectations of improved technology leading to lower energy usage. Higher corn yields per acre do not necessarily lower energy usage. Higher yields could in fact be due to increased energy usage in the form of farm equipment usage, fertilizer usage and irrigation.

While processing technology should continue to improve, AHCE presented no specific information supporting the degree of improvement expected from each new technology, nor information demonstrating the cost-effectiveness of such technologies. The same applies to the improvement suggested by the Illinois Corn Growers Association. Thus, neither the degree nor the likelihood of the benefits suggested by these commenters is clear. Again, like ILSR, AHCE often combines the best technology and farming techniques from widely disparate areas with no demonstration of the appropriateness of the combination.

AHCE's comment that most or all of the corn needed for the renewable oxygenate mandate would come from surplus corn is not credible. The nation's corn surplus has varied widely over the past 10 years due to both increasing yields and several very poor growing seasons. At times, the amount of surplus corn was probably sufficient to supply the existing ethanol industry. However, as shown by the drop in this surplus with recent poor growing seasons, this surplus serves a very necessary agricultural purpose and does not just grow year after year indefinitely. To suggest that this surplus could supply the future ethanol industry assumes that a very sizeable surplus of corn will be grown every year in the absence of this program and never be used. Either an ever increasing amount of corn will be stored or roughly 250-300 million bushels of corn will be discarded each year as it spoiled. EPA finds no creditable evidence that this is now occurring or is projected to occur in the future. Thus, this analysis will continue to assume that the

corn needed to produce ethanol for this program would not have been grown in the absence of this program.

The AHCE comment concerning byproduct credit in ethanol production has already been addressed, as it was based on the ILSR study. Given the above, the overall energy benefits cited by AHCE do not appear to be supportable.

The Minnesota Ethanol Committee's suggested ethanol byproduct energy credit is essentially the same as a "market energy" based credit developed but not used by ILSR. This was the largest of three credits developed by ILSR and probably the least appropriate, as it was based on the relative market values of food and fuels, which has nothing to do with a total fossil energy balance. Thus, this byproduct credit will not be substituted for that used by DOE.

The Sierra Club comment did not provide any additional specific information beyond that already described above with which to address the revised DOE estimates.

b.   Future Ethanol Production Processes

Regarding the energy projections made by Sunthetic Energy of America, their claimed energy savings were based on the unique aspects of their multiple oxygenates (MOP) process. This process combines commercially proven ethanol, methanol, MTBE and ETBE production processes in a way to conserve carbon more efficiently and thus, reduce energy requirements and carbon dioxide emissions.

In the MOP process, the primary energy inputs are fermentable biomass and field butanes or isobutane. Ethanol is produced from any fermentable biomass, methanol is produced from the reaction of carbon dioxide and hydrogen, isobutylene is produced from field butanes, and MTBE and ETBE are produced by reacting ethanol and methanol with the isobutylene. The primary difference between the MOP process and the typical production of alcohols and ethers today is that the feedstocks for methanol production are not produced from natural gas, but as byproducts of the other processes. This is feasible due to the combination of methanol, ethanol and ether production in a single plant. The carbon dioxide is produced during fermentation and the hydrogen is produced from the dehydrogenation of isobutane into isobutylene in preparation for the production of ethers.

Carbon dioxide is normally produced from the fermentation of biomass (corn or other) to produce ethanol. This byproduct is

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sometimes used commercially (e.g., in the production of carbonated beverages), but is also often simply emitted as an off-gas. It is currently not used in the production of transportation fuels. The MOP process combines this carbon dioxide with hydrogen to produce methanol, eliminating the need to steam reform natural gas to produce carbon monoxide and hydrogen as the first step in typical methanol production today.

The hydrogen needed for the methanol production in the MOP process comes from that removed from isobutane in the production of isobutylene, one of the two feedstocks needed to produce MTBE or ETBE. This hydrogen is normally used as fuel gas or is sold to other chemical processors for a wide variety of uses. Some of these uses could be within a refinery, for the production of transportation fuels.

Based on the effective use of both the carbon dioxide and hydrogen byproducts, the MOP process could reduce the energy needed to produce renewable oxygenates when compared to today's processes. However, in order to fully take advantage of producing methanol from byproducts, the amount of each byproduct must be produced in just the right ratio. Sunthetic did not provide EPA with any detailed information demonstrating that this would be the case. Also, this is not a foregone conclusion, since no feedstock can be varied independently of the others in the MOP process. For example, if more carbon dioxide is desired, more corn can be processed. However, this increases ethanol production and thus, the need for isobutylene to produce ETBE. The additional isobutylene causes the production of hydrogen to increase. This in turn leads to the need to increase carbon dioxide production (to produce methanol), leading to a vicious circle. However, if necessary, natural gas could be used as a source of supplemental methanol or hydrogen, allowing the process to be balanced chemically. This would increase energy use somewhat, but overall the process should still provide significant energy benefits relative to current production plants.

The cost of the ethers produced from the MOP process is not known. Thus, the likelihood of the MOP process being used commercially is uncertain. Still, the MOP process is an example of the kind of energy improvement EPA projects could occur in the future which would increase the energy benefits of renewable oxygenates production beyond that projected in the DOE study.

Regarding the NREL estimates of very high efficiency for cellulose-based ethanol production, NREL has published a number of technical papers in both peer reviewed and non-reviewed forums

over the past few years.[26] In these papers, NREL describes processes which at the laboratory stage have reached 500% fossil energy efficiency (i.e., only 2 units of fossil energy are needed to produce 10 units of ethanol and electricity). (American Biofuels appeared to be pointing to the same technology in their comments.) NREL has obtained joint industry financing or shared resource projects with both Amoco and New Energy of Indiana, which indicates that their process is being taken very seriously by large corporations knowledgeable in the energy area. The current drawback to the process is its cost. Currently, ethanol from this process is projected to cost $1.22/gal, though this is vastly lower than the $3.60/gal cost estimated in 1980. NREL projects that it can lower this cost to $0.67/gal by 2002, with an aggressive, focused research effort.

EPA is very encouraged by the progress being made in this area and cited such potential benefits in the proposal. Research in this area has been advancing rapidly and holds the promise of producing ethanol at costs competitive with gasoline without tax subsidies. The primary problem with such technology in the near term is that it still must be proven commercially, and the low projected costs confirmed. Still, with such advancements, the fossil energy benefits of this rule could be substantially larger than those projected by DOE. This is further quantified below.

c.   Hydrocarbon Processing Energy

Regarding Arco's estimates of the energy savings associated with renewable oxygenates, the bulk of their analysis utilized the original DOE study and only differed from the EPA estimate developed for the proposal in its estimate of the energy saved by not having to reduce the RVP of ethanol blends. As can be expected, the Arco results for ETBE are very similar to EPA's estimate made for the proposal. However, Arco projects only a 0.1% energy savings for winter ethanol use, which is well below that projected by EPA or by DOE in its revised study. The difference appears to be in the value for octane and volume assigned to the various oxygenates by the various modelling

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[26] Lynd, Lee R., et.al., "Fuel Ethanol from Cellulosic Biomass," Science, Vol 251, March 16, 1991;
      Bull, Stanley R., et.al., "The U.S. Department of Energy Biofuels Research Program," Presented at Energy from Biomass and Wastes Conference XIV, Orlando Florida, 1990;
      Bull Stanley R., "Economic Stakes of Motor Biofuels and Effects of Industrial Development," Presented at the First Motor Biofuels European Forum, Tours, France, May 1994.

efforts. Without knowledge of the detailed inputs to these
models, EPA will rely on the DOE results, as the DOE model was
found to produce reasonable results when used to project the cost
of the Phase II reformulated gasoline standards last year, as
discussed in the RIA for the final RFG rule.

Regarding API's comment concerning the hydrocarbon
basestocks for ethanol and ETBE RFGs, EPA reviewed the energy
requirements associated with the various hydrocarbon blendstocks
used by DOE and found them all to require the same energy of
production. Thus, it appears that DOE did assume that the same
hydrocarbon basestock would be used with all oxygenates. Review
of EPA's complex model also shows that ETBE and ethanol blended
with the same basestock at constant oxygen content will produce
higher toxics emissions than a similar MTBE blend. While some
additional processing may be necessary to achieve the required
toxics performance, EPA's analysis of the toxics performance of
ethanol and ETBE blends in section IV.A indicates that the
additional processing and energy involved would tend to be
modest. Furthermore, ETBE tends to suppress RVP, so ETBE blends
may require less processing (and less energy) to meet the toxics
requirement than is implied by the analysis in section IV.A.
Thus, under the scenario where ETBE blends are sold in the summer
and ethanol blends in the winter, the differences from the DOE
report's conclusions fall in both directions. However, in the
near term, the energy savings associated with winter ethanol
blends could be slightly smaller than those projected by DOE.

Unfortunately, it is not possible at the present time to
quantify this effect, as very detailed and costly refinery
modelling would have to be performed. Also, the toxics
performance standard may not be constraining on RFG composition
for at least some refiners, given the need to meet VOC and NOx
performance standards and the benzene fuel specification at the
same time, as indicated in section IV.A.

4.   Final Estimates

As demonstrated by the analysis of comments above, there
still appears to be a significant degree of uncertainty in the
energy requirements associated with using various oxygenates in
reformulated gasoline. Documenting energy usage by private
facilities, allocating this energy among various products,
projecting these figures for future production facilities which
will be built under a variety of local and national incentives
all add to the uncertainty. Projecting the type of farmland that
will be used to produce the additional corn and the yield and

energy usage associated with this land was not even attempted by any of the commenters or analysts in any detail.

All this notwithstanding, it appears very unlikely that even the use of marginal farmland would decrease the efficiency of producing ethanol from corn below 100% on a fossil energy basis. The production of methanol from any fossil fuel will be in the range of 65-70% efficient. Given the small changes occurring in the hydrocarbon portion of the blend, it appears almost certain that the use of ethanol or ETBE will produce some degree of energy savings. Given the inability to quantify the effect of the specific farmland to be used for incremental corn production, the latest midpoint or primary estimates made by DOE are probably the most reasonable set of point estimates currently available, if one acknowledges that some degree of uncertainty exists. The results of the revised DOE analysis, including the upper and lower bound estimates, also appear to reasonably bracket the likely energy benefits associated with this program.

The figures in the last column of Table II-1 above show the DOE results for individual summer or winter blends. As can be seen, the energy benefits of the renewable oxygenate program depend on the oxygenates used and the production processes used to produce them, which can vary depending on the season and timeframe of interest.

As described above, in the early years of the program the renewable oxygenate requirement is expected to be met primarily with ethanol blended into winter RFG. For at least the first two years, this ethanol would be produced in existing plants or new plants equipped with current technology. Some diversion of ethanol currently being blended into conventional gasoline may also occur. Small additional quantities of ETBE may be used in summer RFG and ethanol use in summer RFG may decrease, but these shifts and their energy impacts will be very small relative to the effects of the increase in wintertime ethanol use. In the longer term (i.e., after 2-3 years), EPA expects greater amounts of ETBE to be used in summer RFG.

DOE evaluated a scenario where the entire 30% renewable oxygenate requirement was fulfilled with winter ethanol and another scenario where the requirement was fulfilled with ETBE in the summer and ethanol in the winter. DOE's best estimate impacts were taken from Tables 5 and 6 of the revised DOE study, while the upper and lower bound estimates were taken from Table 9. These figures are shown below in Table II-2.

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Table II-2:   Total Fossil Energy Consumption
Under a 30% Renewables Program

Scenario	Energy Requirement (Btu/gal)	Energy Requirement (Btu/gal)	Percent Difference
Near Term			
	MTBE (Year-round)	MTBE (Summer)/ Ethanol (Winter)*	
DOE Best Estimate	129,740	128,949	-0.7%
DOE Lower Bound	129,740	128,572	-0.9%
DOE Upper Bound	129,740	129,091	-0.5%
Mid Term			
	MTBE (Year-round)	ETBE (Summer)/ Ethanol (Winter)*	
DOE Best Estimate	129,740	128,883	-0.6%
DOE Lower Bound	129,740	128,702	-0.8%
DOE Upper Bound	129,740	129,221	-0.4%

* Produced from new ethanol and applicable to 30% of RFG. 70% of RFG not affected by the renewable oxygenate proposal is assumed to contain MTBE.

As shown in Table II-2, if the entire 30 percent renewables requirement is met by blending ethanol not currently being produced into winter RFG, the overall fossil energy consumed in RFG production and use would be 0.7 percent lower than would be the case if MTBE produced from natural gas were the only oxygenate used in RFG. While not accounting for all potential uncertainties in the analyses, the likely range of savings would be 0.5-0.9%. If ETBE is blended into 30% of summer RFG and ethanol blended into 30% of winter RFG, the fossil energy benefits of the program being promulgated today program be 0.6 percent. Again, a reasonable range of potential benefits is 0.4-0.8%.

It should be noted that these fossil energy savings would be smaller if the requirements are met with ethanol displaced from existing markets. However, as discussed in section I above, EPA expects that any ethanol displacement which may occur should be

of short duration and of limited amount. EPA anticipates that
new production capacity for ethanol, ETBE, and potentially
renewable methanol will be added as the market for renewable
oxygenates expands. The benefits of the program may also be
smaller than shown in Table II-2 above, since it assures the
benefits of the full 30% renewables program and does not take
into account the benefits that would have occurred even under the
existing RFG program. EPA projected in Section I that roughly
half of the 30% renewable requirement, or 15% of all RFG, would
have been contained ethanol or ETBE even without this program.
If this projection is correct, the incremental fossil energy
benefits estimated above would be overstated by a factor of two.

The energy benefits of this program could potentially
increase even more in later years, as cellulose-based ethanol
plants are commercialized, and as renewable methanol production
becomes viable. The timing of this and the degree to which
energy requirements may decrease is very uncertain, due to the
need for further technological development in order for these
processes to be economically competitive with corn-based ethanol.
However, the increase in expected energy savings could be
substantial, with the overall ethanol production process yielding
5 times as much energy per unit of fossil energy required (as
claimed by NREL). Factoring this into DOE's best estimate
analysis would more than double the mid term savings of 0.6%
shown above to 1.3%.

B.   Fuel Economy Impacts

The effects of fuel parameters on fuel economy are discussed
in detail in Section IV of the Regulatory Impact Analysis for the
proposed rule for reformulated gasoline[27]. In that analysis, the
data from two different studies were used to analyze the effect
of fuel parameters on fuel economy. The conclusion of the study
was that the overall effect of reformulating gasolines on fuel
economy was close to zero. While individual changes, such as
adding oxygen, lowering T90, lowering aromatics and lowering RVP
do impact fuel economy, when summed there was only a minor
effect. The addition of oxygen was found to lower fuel economy,
as were lowering aromatics and T90. However, lowering RVP was
found to increase fuel economy. The average in-use effect of
simply adding 2.0 weight percent oxygen was found to be a

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[27]   Regulatory Impact Analysis for the Notice of Proposed
Rulemaking for Reformulated Gasoline Program, FSSB, RDSD, OMS, US
EPA, February, 1993.

reduction in fuel economy of approximately 1.8 percent for ETBE or MTBE, or a reduction of about 2.0 percent for ethanol. However, when the effect of the adjustments for RVP, lower aromatics content, and lower T90 (the latter both due to dilution effects) was factored in, the overall fuel economy of ethanol-containing reformulated gasoline was seen to be approximately 0.26 percent lower than that of ETBE and MTBE fuels. In sum, EPA's analysis showed a very small difference in the fuel economy impacts of the use of ethanol relative to either ETBE or MTBE.

C.   Crude Oil Impacts

1.   Basis for the Proposal

        The DOE analysis that was used as the basis for estimating the fossil energy benefits of the proposed rule was also used as the basis for the crude oil impacts. In the case of crude oil usage, however, the adjustment to exclude the solar energy contained in corn was not made, as the solar energy was not included in the crude oil analysis to begin with. However, EPA deducted the crude oil required to reduce the RVP of ethanol-containing RFG, as DOE had evaluated a VOC-controlled RFG under EPA's 1993 proposal, while ethanol is projected to be used predominantly in the winter under the program being promulgated.

        DOE's revised analysis of fossil energy requirements mentioned above also contained updated crude oil requirements. As in the case concerning fossil energy, since the adjustments made by EPA to the original DOE analysis were at best approximate, the updated DOE analysis will be used as the basis here for evaluating comments and any further revisions to the fossil energy impacts associated with the final rule.

        The results of the June, 1994 DOE analysis are shown in Table II-3 below, along with those contained in the TSD for the proposal. Shown are crude oil requirements for MTBE blends (summer and winter), an ETBE blend (summer only) and an ethanol blend (winter only).

**Table II-3: Total Crude Oil Consumption
of Summer and Winter Gasolines**

Oxygenate (Source)	Initial Analysis (for NPRM)		Final Analysis	
	Btu per gallon (Btu/gal)	Change Relative to MTBE	Btu/gal	Change Relative to MTBE
Summer				
Conventional Gasoline	124,205	+12.1%	124,205	+12.0%
MTBE (natural gas)	110,849	---	110,849	---
ETBE				
(From New EtOH)	108,849	-1.8%	108,865	-1.8%
(From Existing EtOH)	108,849	-1.8%	113,557	+2.4%
Winter				
Conventional Gasoline	124,205	+12.1	121,775	+11.9%
MTBE (natural gas)	110,849	---	109,002	---
Ethanol				
(New EtOH)	120,109	+8.4%	116,429	+6.8%
(Existing EtOH)	120,109	+8.4%	121,047	+11.1%

As was the case with the fossil energy analysis, DOE's more recent analysis evaluated the situation where the requirement of this program are met both by shifting ethanol from existing markets and from the production of new ethanol not currently being produced. In the case of crude oil, however, the impact of the source of the ethanol is much more significant than in the case of fossil energy. The reason for this is that utilizing existing ethanol leads, by definition, to no new ethanol production, but merely displaces MTBE with conventional gasoline. MTBE production consumes very little crude, while gasoline is almost entirely crude oil derived. Thus, fulfilling the renewable oxygenates requirement with existing ethanol leads to significant increases in crude oil usage.

Even in the case of new ethanol, however, projected crude oil usage increases. The reason for this is fairly straightforward. The primary crude oil savings associated with oxygenate use is that they displace gasoline in nearly a one-to-one ratio by volume.[28] Due to ethanol's high oxygen content per gallon, less ethanol than MTBE is needed to achieve a given oxygen content and thus, less gasoline is displaced. ETBE, on the other hand, contains less oxygen per gallon than MTBE, so more gasoline is displaced and crude oil usage is decreased, as shown above.

This discussion assumes that the primary energy sources of the various oxygenates are not crude oil-related. The production of methanol utilizes essentially no crude oil, while corn-derived ethanol utilizes very little crude oil. For the ethers, the primary concern is the source of the isobutylene. The isobutylene used by MTBE plants contained within refineries comes from crude oil processing, while that for the large stand-alone ether plants (either domestic or overseas) comes from natural gas. The key question is which source of MTBE will be supplanted by this program. DOE projects that the supplanted MTBE will be entirely natural gas-based. Due to the generally higher cost of natural gas-based ethers relative to refinery-based ethers, this appears reasonable. Thus, generally, all of the oxygenates can be considered to be derived from natural gas and the volume of gasoline displaced by oxygenates will dominate the crude oil impact.

Based on this fact, the use of any oxygenate in RFG causes a significant reduction in oil usage, and thus oil imports, from 6-15%. The issue addressed here is how this potential reduction is affected by the renewable oxygenate program. With or without the program, crude oil usage will decrease with the use of RFG.

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[28] There is a small decrease in fuel economy due to oxygenates' lower heating values, but this effect is essentially the same for all oxygenates at the same oxygen content. Thus, it does not affect the comparison of the various oxygenates here.

2.   Comments on the Proposal

     EPA received a number of comments on the energy benefits
developed in support of the proposal. Many of the comments
addressed the importance of crude oil imports to national
security or the nation's balance of payments. Others reiterated
that this program will not reduce crude oil consumption or
imports.

     A number of commenters claimed additional crude oil savings
for renewable oxygenates, but all the factors they cited have
already been incorporated by both DOE's original and their
revised analyses. Many of these commenters also appeared to
compare the use of renewable oxygenates with non-oxygenated
gasoline, instead of with RFG containing a non-renewable
oxygenate. As shown above, use of any of the oxygenates will
reduce crude oil use compared to non-oxygenated gasoline, but
that was the effect of the final RFG rule, and not the effect of
this rule.

     A number of commenters also made claims regarding the
domestic or imported source of MTBE currently being used in the
U.S. This is not a direct issue of this rule, but does deserve
some mention. Currently much methanol and MTBE is imported into
the U.S., and the increased demand for MTBE associated with the
RFG program is expected to increase these imports. The renewable
oxygenate program will increase the demand for renewable
oxygenates and will also, therefore, reduce the demand for non-
renewable oxygenates, primarily MTBE. In the long term, the
impact will be that a number of MTBE plants may not be built
which otherwise would have been. In this case, it is extremely
difficult to project whether these cancelled plants would have
been domestic or overseas, given that MTBE capacity has been
growing significantly in both areas over the past five years.
There could very well be similar impacts in both areas.

     In the near term, there will definitely be impacts as the
timing of this program is almost immediate and MTBE plants have
already been built to supply much of the oxygenate demand for
RFG. Existing MTBE plants can be categorized into three types:
domestic refinery based, domestic natural gas liquid (NGL) based
and overseas NGL based. The refinery based plants have the
lowest costs, both in terms of operating and fixed costs. Their
isobutylene is a byproduct of other processes (primarily
fluidized catalytic cracking) and their only capital cost is that
for the MTBE plant itself. NGL- based plants have much higher
fixed costs due to the large costs of the equipment needed to
dehydrogenize isobutane to isobutylene. While the fixed costs of

an overseas plant may be higher than domestic plants due to the
additional construction costs associated with more remote
locations and higher transportation costs to the U.S., the butane
costs overseas are extremely low due to the absence of
alternative uses. Domestically, butane has a number of other
chemical and fuel related uses and commands a significant price
on the market. Generally, the lower butane costs overseas will
more than make up for the higher capital investment and probably
will make up for the cost of transporting MTBE to the U.S., as
well. Thus, the plants most at risk in the near term are likely
the domestic NGL based plants. Thus, the MTBE displaced by
ethanol will not likely be crude oil based, consistent with DOE's
assumption, but counter to some commenters. Also, the MTBE
displaced by ethanol may also not be imported MTBE, but domestic
MTBE, again counter to some commenters.

3.   Final Estimates

      Based on the analysis of comments above, the revised DOE
analysis appears to provide a reasonable and supportable estimate
of the crude oil impacts associated with this rule. Based on the
DOE analysis, it appears very likely that the use of ethanol
directly in RFG will increase the use of crude oil in the U.S.,
relative to MTBE, while the use of ETBE will marginally decrease
crude oil usage. The latest midpoint or primary estimates made
by DOE are probably the most reasonable set of point estimates
currently available. The results of the revised DOE analysis,
including the upper and lower bound estimates, also appear to
reasonably bracket the likely energy benefits associated with
this program. As indicated by the small ranges shown in Table
II-4 below, the uncertainty in the crude oil impacts are probably
much smaller than that in the energy savings described earlier in
Section A. above.

      The figures in the last column of Table II-3 above show the
DOE results for individual summer or winter blends. As can be
seen, the energy benefits of the renewable oxygenate program
depend on the oxygenates used and the production processes used
to produce them, which can vary depending on the season and
timeframe of interest.

      As described above, EPA expects ethanol directly blended in
the winter to be the dominant renewable oxygenate in the first
couple years of the program. Beyond that, a mix of ETBE blended
in the summer and ethanol blended in the winter is likely. DOE
evaluated both of these scenarios in their revised report. The
figures for DOE's best estimate scenario were taken from Tables 5
and 6 of the revised DOE study, while the upper and lower bounds

were taken from Table 9. These figures are shown below in Table II-4.

Table II-4: Total RFG Crude Oil Consumption
of a 30% Renewables Requirement

Scenario	Energy Requirement (Btu/gal)	Energy Requirement (Btu/gal)	Percent Difference
Near Term			
Type of Oxygenate Used	MTBE (Year-round)	MTBE (Summer)/ Ethanol (Winter)*	
DOE Best Estimate	109,771	112,006	+2.0%
DOE Lower Bound	109,771	111,966	+2.0%
DOE Upper Bound	109,771	112,076	+2.1%
Mid Term			
	MTBE (Year-round)	ETBE (Summer)/ Ethanol (Winter)*	
DOE Best Estimate	109,771	110,823	+1.0%
DOE Lower Bound	109,771	110,758	+0.9
DOE Upper Bound	109,771	110,868	+1.0%

* Applicable to 30% of RFG. 70% of RFG not affected by the renewable oxygenate proposal contains MTBE.

     As shown in Table II-4, if the entire 30 percent renewables requirement is met by blending ethanol produced in new-technology ethanol plants into winter RFG, total crude oil consumed in RFG production and use would be 0.9-1.0% higher than would be the case if MTBE produced from natural gas were the only oxygenate used in RFG. If ETBE is blended into 30% of summer RFG and ethanol blended into 30% of winter RFG, crude oil consumed in RFG production would increase 2.0-2.1 percent. Given that current ethanol production processes consume little crude oil, the advanced cellulose-based ethanol processes will have little effect on crude oil consumption. To the extent that a significant fraction of the renewable oxygenates required by this program would have been used in reformulated gasoline even without the 30% requirement, the projected incremental impacts of

this rule would be less (e.g., if planned ethanol and ETBE use would have provided 15% of the oxygenates used in RFG, as EPA estimated in section I, then the crude oil benefits of the renewable oxygenate requirement would be roughly half of those just described).

III. Environmental Impacts

A.   Commingling and VOC Emissions

1. Discussion

     Pure ethanol has a Reid vapor pressure (RVP) of 2.4 psi, and
most gasolines will have an RVP of 6.5 to 9.0 psi in the summer
months. When ethanol is mixed with the gasoline, however, a non-
linear increase in RVP is observed. For example, if gasoline
with an original RVP of 8.0 psi is mixed with ethanol at 10% by
volume, the resultant RVP is approximately 9.1 psi. Data exists
showing that most of the RVP boost occurs with relatively small
concentrations of ethanol and that larger concentrations maintain
RVP but do not cause any significant additional RVP boosts.[29]
Figure III-1 shows the RVP boost as a function of the
concentration of ethanol.

Figure III-1: RVP Boost as a Function of Ethanol Concentration
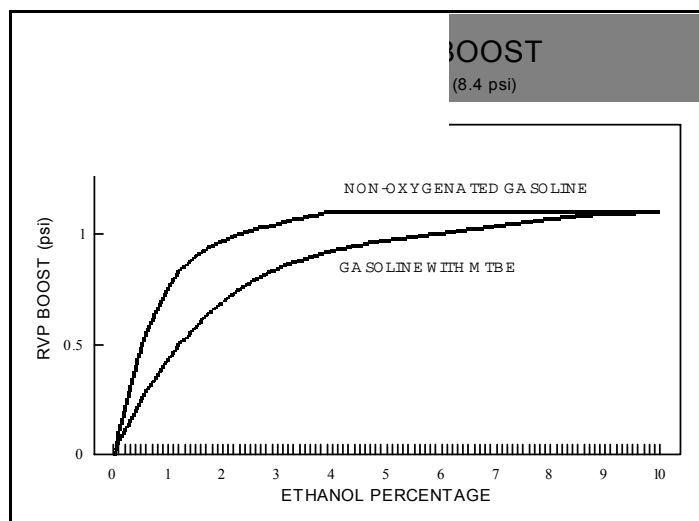
     [29] "Volatility Characteristics of Gasoline-Alcohol and
Gasoline-Ether Fuel Blends," Robert L. Furey, General Motors
Research Laboratories, SAE Paper No. 852116, October 1985.

It is clear that most of the RVP boost occurs at small concentrations of ethanol and that the boost is relatively constant from about 6 volume percent ethanol on up. These increases in RVP are known to have a direct impact on emissions of summertime VOCs. However, the reformulated gasoline program (RFG) effectively limits this RVP boost during the summer months due to its RVP limits under the Simple Model and its VOC emission performance standards under the Complex Model. Hence, refiners must use a lower RVP base gasoline to ensure that ethanol-containing blends do not exceed the maximum allowable RVP or VOC standard.

However, due to the non-linear nature of ethanol's blending RVP, the mixing of ethanol blends with other non-ethanol containing gasolines downstream of the refinery (as may occur in vehicle fuel tanks, for example) can result in an additional vapor pressure increase across the in-use pool of gasoline. This RVP increase caused by fuel mixing is known as the commingling effect[30]. Commingling can significantly increase average in-use fuel volatility, which leads to higher emissions of VOCs. A detailed analysis describing the commingling effect as well as an in-depth discussion of its effect can be found in the Regulatory Impact Analysis[31] (RIA) for the final rule on Reformulated Gasoline (RFG). Since this phenomenon is not included in EPA's Complex Model, the potential VOC increases resulting from commingling are not required to be controlled through changes in RFG composition.

EPA has estimated the impact of commingling on VOC emissions, however. Assuming a 30% market share for ethanol in reformulated gasoline during the summer months, EPA's analysis indicates that the commingling effect causes a 0.15 to 0.20 psi increase in the in-use RVP as shown in Figure III.2. This RVP boost translates to approximately a 2 to 2.5 percent increase in

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[30] "In-Use Volatility Impact of Commingling Ethanol and Non-Ethanol Fuels," Peter J. Caffrey and Paul A. Machiele, U.S. EPA, SAE Paper No. 940765," February/March 1994.

[31] Final Regulatory Impact Analysis for the Reformulated Gasoline Program, FSSB, RDSD, OMS, OAR, US EPA, December 1993, document number V-B-1, EPA Docket A-92-12.

fleet-wide gasoline vehicle VOC emissions. Figure III.2 also shows that most of the commingling effect occurs at small market shares of ethanol and that the commingling boost is virtually flat between 30 and 70 percent market shares of ethanol. Thus, increases in the market share of ethanol beyond 30 percent have little impact on commingling. Increases beyond 70 percent decrease the commingling effect.
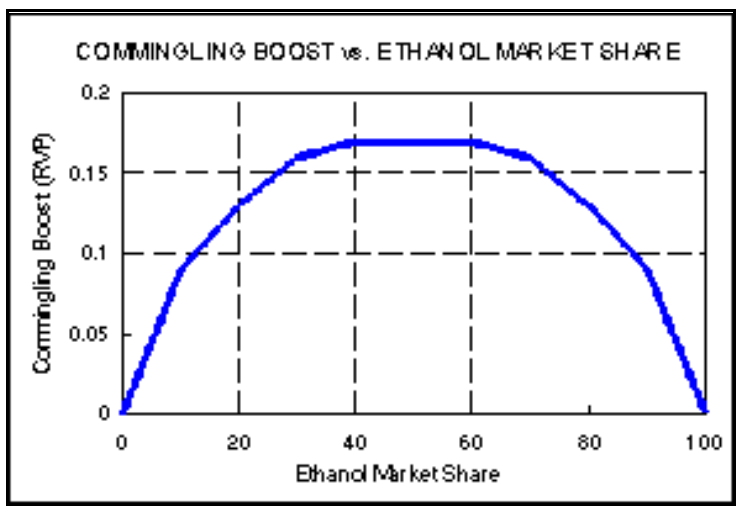
COMMINGLING BOOST vs. ETHANOL MARKET SHARE

Figure III.2: Commingling Boost versus Ethanol Market Share

In contrast, if typical ETBE or MTBE fuels are compared to alcohol fuels, there is no expected increase in VOC emissions from commingling since ether based oxygenated fuels do not

experience an RVP boost upon mixing. EPA's commingling analysis only examined mixing in consumer's vehicle tanks. Other mixing effects were assumed to be eliminated by segregation requirements under the RFG program. Overall, this information leads to the conclusion that the use of ethanol blends in the RFG program may lead to an increase in VOC emissions (or a decrease in net VOC reductions), depending on the level of post-refinery mixing of RFGs containing different oxygenates.

The commingling effect, as described above, plays an important role under the renewable oxygenate (ROXY) program for two reasons. First, because of the additional RVP boost and corresponding increase in VOC emissions that it causes, no credit is given to the use of ethanol to meet the 30 percent requirement in the summer months under the ROXY program. Second, commingling effects due to increased ethanol use outside of the high ozone season may cause detrimental environmental impacts. Many comments have expressed concern over the potential detrimental effects of commingling during the so-called shoulder season. The effects of commingling during the shoulder season and responses to all of the comments concerning commingling effects during the shoulder season are discussed in Section V in this RIA.

2.   Response to Comments

A variety of comments were received concerning EPA's discussion of the commingling impacts of the renewable oxygenate requirement. One comment was that the RVP increase caused by ethanol addition is primarily caused by the water and denaturant content of ethanol-gasoline mixtures. EPA believes that there is no evidence to warrant such a conclusion. While it is possible that the water and denaturant concentrations of ethanol mixtures may effect the magnitude of the commingling effect to a small extent, the wealth of data available as supported by scientific theory presents a compelling argument that ethanol is responsible for the effect. This is discussed in further detail in the RIA for the final rule on RFG.[3]

There were some comments asserting that EPA's commingling analysis was biased because the brand loyalty curve used was "exaggerated" (the comment claims that less brand loyalty exists than what EPA assumed) and that the work was not reviewed by the technical community. EPA's brand loyalty curve is based on data gathered from actual (though limited) consumer loyalty patterns. As the published work points out[2], the results are a strong function of consumer loyalty. However, a sensitivity analysis performed over the range of likely loyalty estimates reveals little difference on the overall commingling effect. Thus, the

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commingling effect is expected to be significant regardless of the assumptions used in determining the brand loyalty curve. Since completion of the RFG final rule, EPA's commingling analysis has been both peer reviewed and published.[2]

There was one comment on the fact that EPA did not account for fuel weathering in the commingling analysis. While the effect of fuel weathering on VOC emissions is not directly included in EPA's commingling analysis, it is included in EPA's emission factor model, MOBILE5a. The effects of fuel weathering on VOC emissions are thus accounted for, because the effect of commingling is input as an RVP increase into MOBILE5a, which then determines the overall emission effects based on the fuel's characteristics, and in that determination fuel weathering is taken into account. Since it is the VOC increase of commingling and not merely the RVP increase that the commingling model was designed to address, it is not necessary to reflect weathering in the commingling model itself.

B.   Distillation

Distillation characteristics of the fuel can have profound effects on both exhaust VOC emissions and evaporative VOC emissions[32]. The impact of distillation on exhaust emissions is modelled in the Complex Model by the fuel parameters RVP, E200 (percentage of fuel evaporated at 200$\,^\circ$F), and E300 (percentage of fuel evaporated at 300$\,^\circ$F). Since each refiner is required to meet a minimum percent reduction in VOC emissions, regardless of the oxygenate used, differences in exhaust emissions resulting from differences in the above fuel distillation characteristics do not impact the analysis of the merits of the use of renewable oxygenates.

However, differences between the distillation characteristics of various oxygenates does impact evaporative emissions of VOC in a manner that is not currently compensated for by the Complex Model. Evaporative emissions are generally more pronounced with alcohol-containing fuels because of the increased low-end volatility of these fuels. Traditionally, the only fuel parameter used by EPA to model evaporative emissions has been the fuel's RVP. However, recent analyses (discussed in

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[32]   Evaporative emissions result from running losses, hot soaks (the times when the vehicle is cooling after operation), refueling, and diurnals (the change in ambient temperature over the course of the day).

a paper by EPA staff[33]) indicate that EPA's MOBILE model does not accurately reflect changes in evaporative emissions (especially fuels containing low boiling point oxygenates) resulting from changes in fuel distillation curves. This discrepancy is a result of the MOBILE model's reliance on RVP (the measure of vapor pressure at a single temperature, 100°F) to correlate the distillation effects to evaporative emissions. EPA's analyses demonstrate that RVP alone appears to be insufficient to determine the effect of fuel volatility on evaporative running loss emissions (the largest source of evaporative emissions) and hot soak emissions of fuels blended with low molecular weight oxygenates. These oxygenates, due to their low boiling points, distort the low end of the blend's distillation curve, thereby causing the correlations between RVP and emissions developed using non-oxygenated gasoline to be inaccurate. This effect is referred to as the "front-end" distillation effect because it reflects the failure of RVP alone to accurately characterize the emissions resulting from the evaporation of lighter compounds (which occur at temperatures experienced during vehicle operation). This phenomenon was not included in either the Simple or Complex Models, and thus presents a concern when determining the net VOC impacts of various oxygenate blends.

As discussed in the RIA for the final rule on RFG and in an EPA staff memorandum[34], if one assumes a 30 percent market share for ethanol in reformulated gasoline during the summer months, the "front-end" distillation effect is estimated to result in as much as a 3 percent increase in gasoline vehicle VOC emissions (relative to CAA baseline gasoline). This number was calculated using a methodology suggested by EPA staff as a result of the aforementioned analyses[5]. Due to its higher boiling point, fuels made with ETBE are expected to have no additional distillation effect on VOC emissions relative to CAA baseline gasoline.[35] The distillation effect of MTBE is expected to contribute to a small

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[33] "Running Loss Emissions from Gasoline-Fueled Motor Vehicles," Christian E. Lindhjem and David J. Korotney, US EPA, SAE Paper No. 931991, November, 1993.

[34] Memorandum from Paul A. Machiele, FSSB, to Richard D. Wilson, Director, Office of Mobile Sources, "Update of the Relative Ozone Reactivity of Reformulated Gasoline Blends," June 11, 1993. Available in Docket A-92-12; Item # IV-B-12.

[35] Letter from Chester J. France, Director, RDSD, to Dr. Gary Whitten, Chief Scientist, Systems Application International, September 24, 1993. Available in Docket A-92-12; Item # IV-C-4.

increase in VOC emissions relative to CAA baseline gasoline. Thus, fuels blended with ethanol are expected to have the largest detrimental "front-end" distillation effects on VOC emissions. Typical characteristics of these fuels and the VOC emission effects expected from their "front-end" distillation characteristics are discussed in greater detail in an EPA letter contained in the docket to the RFG final rule[7]. While estimates have been made in the aforementioned reference on the effects of distillation parameters on VOC emissions, insufficient data exists to confirm the magnitude of these estimates. The limited data available supports the scientific theory and the estimates are based on these available data; however, more in-use testing is necessary to arrive at more meaningful effects of "front-end" distillation parameters on VOC emissions.

C.   Short-Term (Simple Model) Impacts

1.   Effect on Fuel Properties

     The Simple Model will be used in the early years (December 1, 1994 through December 31, 1997) of the RFG and renewable oxygenate (ROXY) programs to certify reformulated gasolines. As indicated in section I, due to the near term lack of ETBE production capacity or production capacity of other renewable oxygenates, it is probable that ethanol will be the primary renewable oxygenate used under the Simple Model. EPA expects that some refiners may find it necessary (at least through 1996) to blend oxygenates in excess of the 2.0 weight percent minimum oxygen requirement in some markets in order to meet the annual requirements of the ROXY program. Specifically, refiners may find it necessary to blend up to 10 percent ethanol by volume during the winter months in those RFG markets with the supply, distribution, and blending capacity to do so and may not have adequate flexibility in the near term to average or trade the additional oxygen credits generated.

     Depending on the type and volume of oxygenate added, the other fuel parameters (sulfur, aromatics, benzene) will be diluted to differing degrees. In general, these dilutions will be beneficial to emissions since lowering any of these fuel parameters generally leads to lower emissions (as supported by the Complex Model). Simple Model compliance calculations will not fully reflect the impact of dilution since they do not include all of the fuel effects that are included in the Complex Model. Nonetheless, EPA would expect that any air quality effects resulting from different levels of dilution will be minimal. One reason is that RFG producers are required under the

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Simple Model not to exceed their 1990 baseline levels of sulfur, T90 (or E300), and olefins, on an annual average basis. These caps limit the risk of any detrimental air quality effects related to differences caused by dilution. (The other fuel parameters are not constrained under the Simple Model, and thus the ROXY rule will have no known impacts on emissions resulting from a change in the concentrations of these parameters.) Another reason is that refiners are unlikely to make investments in processing equipment to produce gasoline during 1995-1997 which will make it more difficult for them to comply with the program's 1998 requirements under the Complex Model. Thus, it is doubtful that a refiner will select an oxygenate based upon the Simple Model that would not allow them to comply with the RFG requirements under the Complex Model. Furthermore, some refiners may opt to use the Complex Model prior to 1998; they would have to control any detrimental environmental effects related to changes in dilution or oxygenate type. Finally, since ETBE use will be limited in the early years of the program, and since the volume of ethanol used may be similar to the volume of MTBE that would otherwise have been used (10 volume percent ethanol vs 11 volume percent MTBE, as explained above), dilution effects resulting from the ROXY program may be small during the first few years of the program.

     One fuel parameter that may be adversely affected in the early years under ROXY would be winter fuels' RVP levels. Winter RVP is expected to increase with increased ethanol use because of the direct RVP boost associated with ethanol blending and the associated commingling effect. The implications of commingling have already been discussed. With regard to the direct increase in winter RVP, it should be noted that ASTM has set voluntary standards for gasoline volatility, and some states have adopted these standards as legal requirements. Thus, at least in some areas, refiners would have to compensate for the RVP boost that occurs when blending alcohols. To the extent that refiners adopt the ASTM standards voluntarily, the RVP levels of winter RFG will be limited.

2.   Effect on VOC Emissions

Because VOCs are a precursor to ozone formation, VOC emissions are of concern primarily during the high ozone season. In the near term, the ROXY rule will affect VOC emissions only to the extent that the effects of fuel changes resulting from this rule are not included in the Simple Model. As discussed previously, these effects are predominantly the commingling effect, "front-end" distillation effects, and dilution effects resulting from oxygenate addition. No negative effects of commingling and distillation should occur during the high ozone season, since the ROXY program does not provide credit for use of alcohols in VOC controlled RFG. To the extent that ETBE displaces either ethanol or MTBE use during the summer months, the net impact of the commingling and front-end distillation effects would be a reduction in VOC emissions over what would have occurred even absent this rule.

Winter emissions of VOCs are unregulated under the RFG program, and the ROXY rule will not change that. The issue of VOC emission increases during the "shoulder season" is addressed in detail in section V.A. With the level of ethanol use expected in the winter season (discussed above), it is possible that non-exhaust VOC emissions may increase due to potential RVP increases.

3. Effect on NOx Emissions

The ROXY program is not expected to impact NOx emissions in either the summer or the winter during the early years of the program. As discussed earlier, winter RVP levels are expected to increase somewhat, while summer RVP levels are expected to be unchanged. However, EPA assumes that the winter RVP level has no effect on NOx emissions under the Simple Model. This point is discussed in detail in the RIA for the final rule on RFG.[3] A comment was received stating that there are an increased number of older cars and higher emitting vehicles in California and that there may be more NOx emissions associated with these vehicles as the oxygen content of the fuel increases. Past EPA test programs have actually shown that normal emitters emit less NOx than do higher emitters on the same oxygenated fuels. Further, there have been no noticeable increases in NOx within any of the individual classes of test vehicles even with higher oxygen concentrations.[3] With regard to NOx emission changes from older cars as a result of oxygenated fuels, very little data exists at present to be able to make any concrete and statistically sound conclusions.

4.   Effect on Toxics Emissions

As discussed above in Section I, the renewable oxygenate program (ROXY) will affect the choice of oxygenates to be used in the RFG program for the required 30 percent oxygen content. Ethanol and ETBE provide smaller toxic emission reductions than do MTBE or TAME, according to both the Simple and Complex Models. As a result, a change in oxygenate type, could affect air toxics emission performance. However, since air toxics emissions are explicitly regulated under the RFG program, any changes in air toxics emission performance would have to be offset such that the performance standards are maintained.

As discussed in section IV.6., to the extent refiners were just meeting the air toxics emission performance standards under the RFG final rule, they would incur greater air toxics compliance costs as a result of the renewable oxygenate program requirements. However, if some refiners, in the process of achieving the VOC and NOx performance requirements would have achieved greater reductions than required by the air toxics standards under the RFG final rule, then, as discussed in section IV.6., their compliance costs would be lower. In this case the additional air toxics emission performance that would have been achieved under the RFG final rule (beyond that required) will no longer occur, and overall air toxics emission performance would be degraded marginally as a result of the renewable oxygenate program. Section IV.6 of this RIA contains a detailed description of the analysis required to evaluate the toxics compliance cost impact of the renewable oxygenate program (i.e. switching from MTBE blends to ETBE/ethanol blends). The main component of the analysis is maintaining octane level (octane matching) using proper amounts of oxygenate and aromatics to arrive at the desired octane level, while at the same time meeting the air toxics standards. Table IV-3 shows typical octane matching fuel scenarios while Tables IV-4 and IV-5 show actual Phase I and Phase II octane-matched fuels, respectively. Finally, Table IV-6 shows the toxics performances of the various octane-matched fuels by Model (Simple or Complex), Phase (I or II), Region (1 or 2) and Season (summer or winter). As shown in Table IV-6, while the potential exists for refiners to have been obtaining greater air toxics emission reductions than required due to reductions in aromatics from octane matching, it is difficult to know at this time to what extent this would have occurred. Refiners may or may not have that much flexibility in adjusting for the octane value of the oxygenates. As a result, it is difficult to know whether the impact of the renewable oxygenate program on air toxics emission performance will effect in-use performance, or just refinery compliance costs.

The ROXY rule does not alter the performance standards under the Simple Model for the impacts on air toxics emissions resulting from changes in oxygenate type. However, aside from the potential impact described above, EPA recognizes that depending on how refiners choose to adjust their fuels to accommodate the increased volume of renewable oxygenates and achieve the required toxics performance, the toxics emission benefits of their Simple Model fuels may be smaller when evaluated using the more comprehensive Complex Model. As explained earlier, this situation arises due to differences between the Simple Model and Complex Model. If some refiners choose to maintain their air toxics emission performance under the Simple Model by reducing aromatics instead of benzene, the toxics benefits estimated under the Complex Model would be somewhat smaller than the toxics benefits estimated under the Simple Model. However, the relative costs and benefits of benzene and aromatics control suggest that most refiners who need to achieve additional air toxics emission reductions to compensate for the smaller toxics benefits of ETBE and ethanol (relative to the benefits of MTBE) will choose to control benzene instead of aromatics. Regardless of which approach refiners take, however, this issue does not exist for RFG certified under early use of the Complex Model, and disappears entirely in 1998 with mandatory use of the Complex Model.

D.   Long-Term (Complex Model) Impacts

1.   Effects on Fuel Properties

In the long term (after January 1, 1998), the Complex Model must be used to certify all reformulated gasolines. By that time, no further changes in average oxygen levels are expected, since the ROXY program will have been in effect for some time permitting refiners to adjust. However, the ROXY program is expected to stimulate the use of ETBE during the summer months and increase the use of ethanol in the winter months; by 1998, it is possible that substantial ETBE capacity could be available. Furthermore, when the Phase II RFG standards take effect in the year 2000, there will be further incentive to use ETBE to meet the stricter performance standards.

Any shifts in oxygenate use resulting from the ROXY program will also cause changes in the concentrations of other fuel parameters in the final gasoline blend, since different oxygenates require different volumes to meet the same oxygen content requirement. The Complex Model will require refiners to account for the dilution-related changes in the level of

aromatics, olefins, sulfur, E200, E300, or benzene resulting from their choice of oxygenate. Hence, there will be no appreciable effects from changes in these fuel properties resulting from the ROXY program.

2.   Effects on VOC Emissions

As discussed earlier, the RFG VOC performance standards remain unchanged by the ROXY rule. The VOC emission performance will also remain unchanged as predicted by the Complex Model since it accounts for all known VOC emission effects caused by dilution-related changes. Hence, VOC emissions will only be impacted as a result of the commingling and front-end distillation effects described previously. In the summer, since the ROXY rule does not encourage the use of ethanol, no additional VOC emissions are expected (over what would have occurred without the ROXY program). To the extent that the ROXY program does not encourage the use of ethanol in the summer, there may be some reductions in the commingling effect if ETBE use increases. In addition, if ETBE use increases in the summer (as expected), no commingling risks exist and possible benefits are foreseen as a result of reductions in the commingling and distillation effects.

As in the near term of the program, the only risks in the long term in the wintertime come from increased non-exhaust emissions due to the RVP boost from increased ethanol use. However, this effect is expected to have minimal impact, as discussed in the "shoulder season" discussion below in Section V.A.

3.   Effect on NOx Emissions

There was some concern expressed in comments that increased oxygen concentrations under the ROXY program would lead to higher NOx emissions. With the exception of the first year of the program when the blending capacity of renewable oxygenates may be limited, causing some refiners to blend ethanol at higher levels in the winter, oxygen concentrations are not expected to be higher under the ROXY program than what is required in the RFG program. Regardless, there is expected to be no effect of the ROXY rule on NOx emissions, since NOx effects are fully constrained by the complex model for RFG and by separate summer and year-round standards. Increased winter RVPs (resulting from increased ethanol use) are expected to have essentially no effect on NOx emissions, as discussed in detail in the RIA for the final rule on RFG.

4.   Effect on Toxics Emissions

     According to the Complex Model, ethanol and ETBE provide
smaller toxics benefits than do MTBE or TAME when used at
identical oxygen content levels (see section IV of this RIA for
additional details). However, since air toxics emissions are
explicitly regulated under the RFG program, any changes in air
toxics emission performance would have to be offset such that the
performance standards are maintained.

     As discussed in section C.4 above, however, if in the
process of achieving the VOC and NOx performance requirements a
refiner would have achieved greater reductions than required by
the air toxics standards under the RFG final rule, then their
compliance costs would be lower. The additional air toxics
emission performance that would have been achieved under the RFG
final rule (beyond that required) would no longer occur, and
overall air toxics emission performance would be degraded
marginally as a result of the renewable oxygenate program.

E.   Particulate Matter (PM-10) Emissions

     EPA received a few comments expressing concern that EPA had
not determined whether particulate emissions from motor vehicles
will increase as a result of the renewable oxygenate requirement,
because NOx and N_2O could be increased (due to more oxygen) and
that, in turn, could impact particulate emissions. As discussed
earlier, NOx emissions are not expected to increase under the
ROXY rule since oxygen levels are expected to be no higher than
what is required under the RFG program. Thus, EPA has no basis
to determine that PM-10 emissions will increase as a result of
increased NOx emissions resulting from this rule. Another
comment indicated that PM-10 emissions would decrease as
aromatics content decrease which would occur with increased use
of ETBE. EPA is currently unaware of any data which shows how
various fuel parameters influence the formation of PM-10
emissions in gasoline powered vehicles and thus cannot directly
conclude that lowering aromatic content of fuels would result in
lower PM-10 emissions. However, lowering aromatics does have the
effect of lowering NOx under the Complex Model and EPA
acknowledges the fact that lowered NOx emissions probably
indirectly leads to the lower PM-10 emissions due to the
combustion chemistry involved in producing the two compounds.

F.   Carbon Monoxide Emissions

     Carbon monoxide emissions are not regulated directly by
either the RFG program or the ROXY program. However, carbon
monoxide emissions can be affected by gasoline properties.
Higher oxygen levels are known to result in large reductions in
CO emissions, and lower RVP levels are known to result in small
reductions in carbon monoxide at temperatures above 45 degrees
Fahrenheit. Both of these effects are currently incorporated in
EPA's MOBILE5a in-use emission model.

     CO emissions are primarily a wintertime issue and are
addressed directly by the oxygen content requirements of the
wintertime oxy-fuels program for CO non-attainment areas. (Since
summer RVP levels are controlled by the RFG performance
standards, no change in CO emission levels is anticipated during
the summer months.) The ROXY rule will not change the oxygenated
fuel program's requirements and also will not change RFG's oxygen
content requirements. Further, there would be no effect in
winter months (when RVP is not constrained by the RFG program)
due to increased ethanol use on the colder days when most CO
exceedances occur, since RVP is not believed to affect CO
emissions below 45 degrees Fahrenheit. There was a comment
regarding the fact that RVP increases tend to increase CO
emissions to a greater extent at high values of RVP. The comment
suggested that a 12.6 RVP fuel caused a 6.6 percent increase in
CO emissions when compared to a 11.5 RVP fuel. However, these
high RVP fuels are expected to be in-use only in the winter
season during which time the CO effects due to RVP changes are
expected to be small (as discussed above). The only effect of
this ROXY rule on CO emissions would be a potential small
increase due to increased RVP levels resulting from increased
ethanol use on those winter days with temperatures above 45
degrees Fahrenheit. However, such small detrimental effects from
higher RVP's should be more than offset by expected large CO
reductions from increased wintertime oxygen addition into
gasolines especially in the near term as a result of the ROXY
program. This was supported by another comment stating that 10
percent ethanol blends would reduce carbon monoxide emissions.
The comment asserts that CO emissions would increase with every 1
psi increase in RVP; however, that increase would be offset by a
17-33 percent decrease in CO emissions from the increased oxygen
content of the ethanol fuel. EPA acknowledges the fact that
oxygen addition has a larger effect on reducing CO emissions than
does RVP on increasing CO emissions.

     Other fuel parameters (besides RVP and oxygen content) may
also affect carbon monoxide emissions. However, a mathematical

model for CO incorporating other fuel parameters is not yet available. Any such effects would also be limited by the constraints placed on these fuel parameters by the VOC, NOx and toxics RFG emission performance standards.

G.   Global Warming Implications

The preamble and technical support document for the proposal presented EPA's estimates of the potential global warming impacts, as represented by emissions of CO_2 and other greenhouse gases, of the 30% renewable oxygenate requirement. EPA analyzed the lifecycle ("cradle-to-grave") emissions from the production and use of gasoline containing various oxygenates. The CO_2 and CO_2-equivalent[36] emissions from the production and use of ethanol-containing gasolines were compared to the emissions from the production and use of MTBE-containing gasoline. EPA concluded that the production and use of ethanol blends (when the ethanol was produced from corn) could result in a reduction in CO_2 emissions of up to 3% relative to the production and use of MTBE blends. Furthermore, EPA concluded that the use of blends containing ethanol produced from cellulose (e.g., nontraditional feedstocks such as wood or municipal waste) had even greater potential for reductions relative to the use of MTBE blends. The CO_2-equivalent emissions impacts of ethanol blends compared to MTBE blends were not as favorable. Since corn farming was shown to result in significant amounts of N_2O emissions, and since N_2O is considered to be a very potent greenhouse gas relative to CO_2, the overall CO_2-equivalent emissions from ethanol blends were estimated to be relatively high.

Many comments were received in response to EPA's analysis. A large number of these presented data and analyses specific to a single state or region. Since the relevance of these types of comments to the evaluation of a national program is limited, EPA was unable to consider much of this information in developing the renewable oxygenate program. Other comments consisted of statements that were not supported by enough information for EPA to evaluate their applicability to this rulemaking, and thus could not be addressed.

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[36] CO_2-equivalent emissions represent a weighted impact of the emissions of all greenhouse gases, including CH_4, N_2O, NOx, CO, and VOC (or NMHC), in addition to CO_2. For the proposal, EPA determined CO_2-equivalent emissions using global warming potential factors developed by the Intergovernmental Panel on Climate Change (IPCC) in 1990.

Of the comments that were directly applicable, however, a broad range of opinions and analyses were represented. A number of individuals raised concerns with the accuracy and completeness of EPA's analysis, citing the current level of scientific uncertainty associated with quantifying lifecycle greenhouse gas emissions. Many of these comments pointed out the difficulty in measuring the lifecycle emissions from the production and use of ethanol, since farming practices and conversion technologies vary and since technologies will likely change in the future.[37] Testimony presented at the January 14, 1994 hearing on this rulemaking by Oak Ridge National Laboratory (ORNL)[38] stated that it is likely that the use of ethanol as a gasoline supplement will lead to a reduction in greenhouse gas emissions, particularly when the best of current technologies is considered. However, ORNL also cited work by Mark A. DeLuchi of the University of California-Davis which shows ethanol use resulting in a higher level of greenhouse gas emissions. ORNL explained that the reason for this difference between analyses was the wide variation in the assumptions one can use (e.g., does one assume average or best of current technology), and concluded that it is difficult to calculate with precision the greenhouse gas emissions resulting from the production and use of ethanol.

Some commenters questioned the significance of the global warming implications of the program, given the small magnitude of the values calculated by EPA and the lack of consensus regarding the contribution of various greenhouse gases to global warming. For example, ORNL suggested that EPA may want to de-emphasize the importance of NOx and N_2O emissions in determining CO_2-equivalence due to the uncertainty in the scientific community surrounding the relative global warming potentials of these greenhouse gases. Other commenters, however, stressed the

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[37] These statements often were used by the commenters to support the recommendation that EPA not pursue performance standards for renewable oxygenates based either upon energy consumption or greenhouse gas emissions. Due to this uncertainty as well as a number of other concerns EPA is not pursuing a performance standard for renewable oxygenates at this time; see the preamble for further information.

[38] Transcript of the testimony of Gregg Marland, Senior Staff Scientist, Oak Ridge National Laboratory, at the public hearing before the Environmental Protection Agency in the matter of Regulation of Fuels and Fuel Additives; Standards for Reformulated and Conventional Gasoline, Docket A-93-49, Hyatt Regency, Crystal City, Virginia, Friday, January 14, 1994.

importance of accounting for emissions of N_2O. (Consultation
with EPA's Global Change Division reveals that there is general
consensus in the scientific community regarding the global
warming potential of N_2O as a greenhouse gas, although there is
substantial disagreement about the relative importance of other
gases, particularly NOx and VOC, emissions as contributors to
global warming.) A number of comments, including those from
ORNL, questioned the use of the IPCC global warming potential
numbers from 1990 to determine CO_2-equivalence, since the IPCC
had issued revised numbers in 1992. The newer IPCC global
warming potentials place less emphasis on some of the gases than
the previous numbers, although CH_4 and N_2O are still considered
to be significant contributors to the greenhouse effect.

     As discussed in section II, other commenters cited or
presented analyses which supported the conclusion that the
production of ethanol using current technologies leads to fewer
CO_2 emissions than those resulting from the gasoline which is
displaced by the ethanol. Several comments identified future
ethanol production technologies which would lead to even greater
emissions reductions, particularly if the renewable oxygenate
program encouraged research and development in this area. Other
comments asserted (and provided data to support) that there have
been significant improvements in the energy efficiency of farming
techniques, leading to significant reductions in emissions from
these processes. There were also comments received which
contradicted many of these claims.

     As the comments cited above indicate, opinions and analyses
of the greenhouse gas emissions and corresponding global warming
implications of the ROXY program vary widely. Many of these
comments also affect the fossil energy impacts of the ROXY
program, and as such are addressed directly in Section 2 of this
Regulatory Impact Analysis. Upon further analysis, it was
determined that insufficient information was available to allow
for a thorough investigation and development of an accurate
accounting of the greenhouse gas emissions and global warming
implications of this rule. This conclusion was supported by the
content and variety of the comments received.   Hence, EPA did
not believe it worthwhile to revise the original estimate of
lifecycle greenhouse gas emissions from the use of renewable
oxygenates for the final rulemaking. For completeness, an
overview of the changes that would have been made are presented
below in subsection 4. The remainder of this section will
address the near term and future global warming implications of
the 30% renewable oxygenate requirement which can be identified
at this time. In addition, other comments received on this topic
in the proposal are addressed.

1.   Near Term Implications

     EPA received a number of comments which identified the near
term global warming implications of the 30% renewable oxygenate
requirement. Testimony provided by the National Renewable Energy
Laboratory (NREL)[39] at the January 14, 1994 public hearing stated
that current ethanol production results in a beneficial ratio of
energy produced to fossil energy consumed, thereby limiting the
net release of CO_2 resulting from the production of ethanol.
Comments from Oak Ridge National Laboratory and others supported
this statement. The U.S. Department of Agriculture (USDA)[40]
concluded that a gallon of ethanol results in 30% fewer CO_2
emissions than a gallon of gasoline, and also that increased
ethanol production would result in little to no net increase in
N_2O emissions (and possibly a net decrease). USDA also presented
an analysis indicating that the N_2O emissions from soybean
production (a crop often rotated with corn) are likely higher
than those from corn, but also emphasized the scientific
uncertainty in determining N_2O emissions associated with farming.
     However, most of these comments compared the energy
consumption and greenhouse gas emissions from the use of ethanol
(as a neat fuel or as a gasoline supplement) to the use of non-
oxygenated gasoline. Although others presented information
contradicting these claims, based upon the information provided
it is reasonable to assume that ethanol production will have in
the worst case negligible impacts in terms of greenhouse gas
emissions, and could have beneficial impacts. Unfortunately,
although such information is useful in analyzing the impacts of
this rule, it does not directly address a comparison of the
implications of the use of renewable oxygenates compared to the
use of nonrenewable oxygenates.

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[39]   Statement of Dr. Charles E. Wyman, Director, Alternative
Fuels Division, National Renewable Energy Laboratory, before the
U.S. Environmental Protection Agency regarding Public Docket A-
93-49, January 14, 1994.

[40]   U. S. Department of Agriculture, "Comments Concerning
the Environmental Protection Agency's Regulation of Fuels and
Fuel Additives: Renewable Oxygenate Requirement for Reformulated
Gasoline Proposed Rule," February 14, 1994, (as submitted in a
letter from Mike Espy, Secretary of Agriculture, to Carol
Browner, EPA Administrator).

A study by the U.S. Department of Energy (DOE)[41,42] better addresses the greenhouse gas emissions impact of the renewable oxygenate program. The DOE study, based largely on a model of lifecycle emissions developed by Mark DeLuchi, indicates that CO_2-equivalent emissions would be higher for a range of scenarios of ethanol and/or ETBE use to meet the 30% requirement[43] when compared to use of only MTBE year-round. If ETBE is used in the summer and ethanol in the winter, CO_2-equivalent emissions could be equal to or up to 0.5% higher (0.2-0.6% higher when the analysis is based on data taken from HO or from USDA respectively) than those from the use of MTBE, depending on the source of the ethanol (new or existing capacity) and the assumptions made regarding the efficiency of corn farming and ethanol production techniques. If the program were met entirely with ethanol in the winter, emissions would be 0.1-0.7% higher (under all cases considered), depending on the use of new versus existing ethanol, respectively.

Although DOE's numbers show a trend of slightly greater CO_2-equivalent emissions from the use of ethanol blends, the uncertainty in these types of estimates and in determining CO_2-equivalence (as acknowledged by DOE and supported by comments on this topic from Oak Ridge National Laboratory and others cited above) is significant. Furthermore, as discussed above, there is limited agreement on how to determine the overall CO_2-equivalence of various greenhouse gases, so the overall global warming implications of the use of ethanol blends is uncertain. Overall, EPA has reached the conclusion that the global warming impacts of this program will likely be equivalent to those that would occur without the program, in the near term. DOE's June 1994 report also concludes that there will be no change in CO_2 emissions given the uncertainty in their analysis. EPA's conclusion is further supported by the fact that it is highly unlikely that

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[41] Singh, Margaret, "Energy Requirements and CO2-Equivalent Emissions of RFG," Prepared by Argonne National Laboratory for Barry McNutt, U.S. Department of Energy, March 17, 1994 (draft).

[42] Singh, Margaret, "Analysis Memorandum: Energy Requirements and CO2-Equivalent Emissions of RFG," Argonne National Laboratory, June 6, 1994.

[43] The DOE study presents analyses of scenarios where the program is met entirely with ethanol in the winter and where the program is met with a combination of ethanol in the winter and ETBE in the summer.

absolutely no ethanol/ETBE use would have occurred in the RFG program absent the 30% requirement.

2.   Longer Term Implications

In the Technical Support Document for the proposal, EPA cited the development of new, more efficient processes for producing ethanol from a variety of feedstocks. These new processes would consume less fossil energy, and thus reduce the contribution of ethanol production to greenhouse gas emissions. EPA also pointed to improvements in farming techniques which would further reduce the greenhouse gas emissions from corn farming for ethanol production. Overall, EPA concluded that in the long term the use of renewable oxygenates would yield an even more favorable impact on the greenhouse gas emissions resulting from the use of reformulated gasoline (relative to the use of nonrenewable oxygenates) than in the near term.

This conclusion is supported by a large number of comments received. In the testimony at the January 14, 1994 hearing, NREL stated that ethanol produced from cellulosic biomass requires one-fifth as much fossil fuel energy inputs as the energy produced, and consequently reduces net CO_2 emissions by about 90% compared to gasoline. NREL further commented that the use of fossil fuels to produce ethanol could be eliminated completely by replacing them with renewables, resulting in virtually zero CO_2 emissions. The Department of Agriculture, in comments submitted on the proposal, also identified the likelihood that the development of new feedstocks (particularly agricultural and municipal waste products) and new, more efficient production technologies will result in reduced emissions of CO_2 related to fuel ethanol use. USDA and others also cited a variety of improved farming techniques (improved yields, reduced fertilizer consumption, low till techniques) which can reduce emissions of CO_2 and other greenhouse gases, particularly N_2O. Many commenters also noted that by expanding the market for renewable oxygenates, the program will accelerate the introduction of these more efficient feedstock and oxygenate production technologies.

3.   Additional Comments

     Many other comments were received related to the global
warming impacts of the ROXY program.   One commenter noted that
to the degree that improved farming techniques increase the level
of carbon sequestration in soil, the global warming benefits of
the use of renewable oxygenates is magnified.   Another comment
stated that biomass (i.e., non-grain feedstocks for ethanol) can
be grown will less harm to the soil, thereby improving the carbon
retention as well as reducing the need for large amounts of
watering and artificial enhancement of the soil.

     Several comments questioned why EPA would "mandate" a
reduction in greenhouse gas emissions when the Administration's
Climate Change Action Plan targets voluntary actions on the part
of industry.   The reader is directed to the preamble to this
rulemaking for a discussion of EPA's rationale for finalizing
this program.

4.   Recommended Approach for Revised Analysis

     As noted above, many comments were received that pointed out
the uncertainty in the numbers generated by EPA and in the
overall methodology for determining lifecycle greenhouse gas
emissions from the use of renewable oxygenates.   Many also cited
the lack of consensus about the urgency of global warming, and in
the methods for determining the relative importance of greenhouse
gases.   Most of these comments did not provide sufficient
information to allow EPA to re-evaluate the original analysis in
a complete manner.   In addition, information on future
technologies for ethanol production and farming methods was
incomplete, and the literature does not contain all of the
information needed to analyze them.   Hence, EPA was unable to
revise the original evaluation of the CO_2 and CO_2-equivalent
emissions resulting from the use of renewable oxygenates.

     However, a number of corrections that could be made to the
analysis should it be updated were identified, and are worthy of
mention.   First, several errors discovered in the spreadsheet
used for the calculations would need to be corrected.   One was an
error in calculating the emissions resulting from the
denitrification of fertilizer (yielding an error in estimating
these emissions that is high by a factor of two).   Another error
was the omission in the calculations for the "worst case"
scenarios for ethanol production of the higher emission factors
for the farming and fuel production steps; correcting this would
make the worst case scenarios even higher in emissions.   Another
potential change to the analysis of greenhouse gas emissions

resulting from the renewable oxygenate program would be to add an analysis of ETBE, which was not included in the original version. EPA would also recommend using the updated 1992 IPCC global warming potentials, although this change would probably not affect the conclusions reached about the relative impacts of the various oxygenates since the gases that have been de-emphasized by the IPCC do not contribute greatly to the overall CO_2-equivalence. Finally, it would be useful to develop better vehicle emission factors for each oxygenated gasoline analyzed, using the MOBILE5a model and assumptions regarding reformulated gasoline. (The original analysis used MOBILE4.1, which does not allow for the modelling of reformulated gasoline.) While this is not an exhaustive list of the corrections that could be made to EPA's original analysis, it gives some indication of potential changes should the reader want to revisit that work in light of newly received information.

H.   Health Effects

       A number of comments were received regarding the health effects of renewable oxygenate use, particularly of the use of ETBE. Some commenters stated that EPA should quantify the health effects of ETBE before issuing the renewable oxygenate requirement, since this program would serve to promote the use of ETBE. Other comments cited existing (limited) data on the toxicity of ETBE, or drew a comparison to MTBE, to conclude that there should be no concerns with increased use of ETBE.

       At this time, health studies of ETBE are being initiated, since virtually no studies of the impacts of exposure to this chemical or its combustion products exist. It is uncertain whether unique concerns may exist with ETBE as compared to the ethanol, MTBE, and/or other compounds it could displace; the work in progress is designed to resolve these uncertainties. However, under the recently promulgated requirements for fuel and fuel additive registration[44], the health impacts of the emissions from the use of ETBE, or any oxygenate, must be established. If sufficient information is not provided to EPA as proscribed by that program, ETBE producers will not be able to sell their product in this country. In the event that this information indicates any significant health risks with the use of ETBE, the Agency will consider the implications of the renewable oxygenate program in light of this new information.

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       [44] U.S. EPA, Fuels and Fuel Additives Registration Regulation: Final Rule, Federal Register, June 27, 1994.

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I.   Other Comments on Environmental Impacts

     A number of other comments on the environmental impacts of
the renewable oxygenate program were also received. One comment
concerned the potential for increased environmental risk from the
greater number of water shipments of oxygenated fuels and the
corresponding increased possibility of spills. As discussed in
detail in Section I.F of this Regulatory Impact Analysis, there
is expected to be no increase in overall fuel shipped (there is
expected to be more oxygenate but less crude) as a result of the
ROXY rule and thus no significant increase in the number of
spills is expected.

     Another comment stated that EPA's complex model did not
account for reduced VOC and CO emissions during enrichment which
occurs when vehicles are operated at full or near-full throttle.
There is currently very limited data relating enrichment
characteristics to fuel parameters and to emissions. Regardless,
there is expected to be no impact of the ROXY program on overall
oxygen use in the long term and thus enrichment should not be
greatly affected. To the extent that there may be possible
benefits of reduced VOC and CO emissions during enrichment, it is
not expected to occur under this program except perhaps in the
very short term when added oxygen may be used.

     Another commenter contended that refinery NOx and VOC
emissions are reduced with the use of ETBE over MTBE since it
requires a reduced reformer severity. EPA acknowledges this
comment as being beneficial for emissions as long as the refinery
is located in sufficient proximity to non-attainment areas.
Otherwise, this effect is inconsequential in the context of the
reformulated gasoline program, which is designed to reduce the
formation of ozone in certain areas with significant ozone
problems.

     Another comment suggested that EPA did not investigate the
impacts of ethanol on fuel tank and fuel line permeation. Thus,
permeation through fuel lines and from the fuel tank would lead
to higher evaporative VOC emissions for alcohol-containing fuels.
EPA is currently unaware of sufficient data showing the effects
of ethanol on fuel permeation through fuel lines and from vehicle
fuel tanks. EPA acknowledges that these phenomena will occur
when alcohol fuels are used due to their highly polar nature (and
affinity to evaporate) and the highly non-polar nature of fuel
lines and tanks. However, until more reliable data are available
to correlate permeation characteristics to fuel volatility and
chemical characteristics, no definite conclusions can be drawn.

Finally, a comment was received which claimed that this program could help to reduce the large amount of cellulosic material accumulating in landfills. In the near term, EPA does not believe that the ROXY program would have any significant effect on reducing the amount of cellulosic material being produced, because it is unlikely that cellulose will be used to any great extent to make ethanol or other renewable oxygenates. However, in the long run, increased use of cellulosic matter to produce renewable oxygenates is a possibility, and to the extent that this reduces the volume of materials which end up in landfills, it will be an added benefit of the ROXY program.

IV. Economic Impacts

     EPA's analysis of the renewable program's direct and
indirect economic impacts is presented in this section. The
analysis compares the economic impact of complying with the
requirements of both the RFG program and the renewable oxygenate
program to the economic impact of complying with the RFG program
in the absence of the renewable oxygenate program. Two key
points should be noted regarding the analysis presented below.
First, EPA examined the economic impact of the increase in
ethanol use expected to result from the renewables program. EPA
expects that a substantial amount of renewable oxygenates would
have been blended in RFG in the absence of the renewables
program, and the Agency does not believe that the costs and
benefits of this quantity of renewables can properly be assigned
to the renewables program. Second, EPA assumed that the
incremental renewable oxygenate use would be in the form of
ethanol, for reasons discussed in the preamble and in this
section, and that this incremental ethanol would displace MTBE on
an oxygen content basis. As a result, each gallon of ethanol was
projected to displace approximately 1.9 gallons of MTBE from RFG
markets.

     EPA received numerous comments on the economic impact of the
renewable oxygenate program. These comments addressed a range of
topics, including the direct costs of the program, the indirect
effects of the renewables requirement on oxygenate producers and
refiners, the indirect benefits of the program to the farm
economy, the impact of the program on the balance of trade and
oil imports, and the benefits and disadvantages of a phase-in of
the 30 percent requirement. In general, commenters from the
ethanol industry, farm groups, USDA, and midwestern States argued
that the direct costs of the program would be small (or even
negative), that the program would have enormous indirect benefits
to the economy as a whole and the farm economy in particular,
that the indirect costs of the program were minimal, that the
program would reduce imports of crude oil and MTBE, and that
existing ethanol supply would be adequate to support the full 30
percent renewables requirement in 1995. They also argued that
the loss in tax revenues resulting from the renewables program
would be more than offset by reductions in farm deficiency
payments. Commenters from environmental groups, States outside
the midwest, the oil industry, ether producers, methanol
producers, and State regulators argued that the program was
unnecessary given ethanol's ability to compete without it, that
the program would not reduce crude oil imports, that the program

would reduce Federal tax revenues at a time of budget deficits, that ethanol supplies would not be adequate to permit full implementation in 1995, that the leadtime to make the necessary changes to accommodate the program was insufficient, and that the program would impose large direct and indirect costs.

Many of these comments either did not address the effects of the renewables program *per se* or did not address the impact of the renewables program in the context of the RFG and other fuels programs. Commenters tended to focus on the costs and benefits of projected total ethanol use rather than examining the effect of the incremental increase in ethanol use resulting from the renewables program. In other cases, insufficient information was provided to support the claims being made. The following discussion incorporates relevant information from or addresses the points raised by the comments received which were substantive and applicable to this analysis.

A.   Fuel and Blendstock Costs

The fuel and blendstock-related costs of the renewable oxygenate program can be divided into several distinct pieces. First, there are the additional direct oxygenate production costs of the additional ethanol use resulting from the program. Second, there are the costs associated with transporting the additional ethanol to its ultimate markets. Third, there are the costs incurred to construct additional tankage and storage capacity at terminals and ports. Fourth, there are the costs incurred to construct additional blending capacity. Fifth, there are the added costs for toxics compliance, since otherwise-identical fuels result in slightly higher toxics emissions when oxygenated with ethanol than when blended with MTBE or TAME.

There may also be additional costs stemming from earlier use of ETBE than might otherwise have been the case. Aside from 1996, however, these costs must be less than the costs of winter ethanol if ETBE is used instead of winter ethanol to meet the renewables requirement. In 1996, some ETBE (which can be produced from summer ethanol) may need to be used to meet the renewables requirement without diverting ethanol from existing markets, since projected winter ethanol capacity does not appear to be sufficient to supply the entire 30 percent renewables requirement; alternatively, additional storage capacity could be brought on-line by then to permit ethanol produced in the summer to be stored for winter use. Sufficient additional winter ethanol capacity is expected to be available by 1997 to meet the entire 30 percent requirement without relying on ETBE production

or increased storage of summer ethanol. By the year 2000, however, EPA believes the stricter standards of the Phase II RFG program will encourage the use of ETBE, independent of the renewables requirement. These points are discussed more fully in section I.

1.   Expected Increase in Ethanol Market Share

When fully phased in, the renewable oxygenate program will assure a 30 percent minimum market share for renewable oxygenates. As discussed in section I, EPA expects that this minimum requirement will be met via ethanol and its derivatives, at least in the short term. At the same time, some ethanol use is likely to occur even in the absence of the renewable oxygenate program. Since the cost of the program depends on the additional ethanol used as a result of the program, it is necessary to estimate what the ethanol market share would have been in the absence of the renewables rule. In section I.D, EPA estimated this *ex ante* market share by determining the amount of ethanol capacity being added prior to the announcement of the renewable oxygenate program proposal in December of 1993. Such capacity could reasonably be interpreted to be intended to meet the expected growth in the market for ethanol resulting solely from the RFG program, independent of the incentives for ethanol use created by the not-yet-proposed renewables program.

The analysis presented in section I.D indicates that prior to EPA's December 1993 renewables proposal, approximately 236 million gallons of additional annual ethanol capacity was being built to satisfy the demands of the RFG program. In addition, approximately 280 million gallons of ethanol already was being blended into gasoline in RFG markets in 1993 (see Appendix I). Based on these figures, it appears that approximately 516 million gallons of ethanol could have been blended into RFG even without the renewables program.

However, not all of this ethanol would help satisfy the renewables requirement since ethanol blended into summer RFG would not count towards the 30 percent renewables requirement promulgated under the renewables rule. Of the 236 million gallons of new ethanol capacity being built to meet the needs of the RFG program, only 127 million gallons would be produced during those months when ethanol blended into RFG receives credit toward the renewables requirement. Of the 280 million gallons of existing ethanol blended in RFG areas in 1993, only 180 million gallons were blended during months when it would receive credit toward the renewables requirement. An additional 81 million gallons of winter ethanol capacity was available (as discussed in

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section I.D) but not utilized in 1993, some of which likely would have been used to supply oxygenate for RFG even in the absence of the renewables program.

These three potential sources of winter ethanol supply amount to 307-388 million gallons of winter ethanol capacity that could have been used to supply the RFG program in the absence of the renewables program, with the precise level depending on how much unused capacity would have been used to meet the demands of the RFG program. This volume of ethanol would have been sufficient to meet the minimum oxygen content of 13.8 to 17.4 percent of the total RFG market. Since it is unlikely that all of the existing excess capacity would have been used to satisfy the RFG program, EPA has estimated that existing capacity and capacity planned for the RFG program before the renewables requirement was proposed could supply enough winter ethanol to meet the minimum oxygen content of as much as 15% of the total RFG market. The renewables program will require an additional 15% of the minimum oxygen content to come from renewable oxygenates in order to meet the 30% renewables requirement. If this additional oxygenate were in the form of ethanol, it would amount to 335 million gallons. Hence EPA has concluded that the renewable oxygenate program will increase demand for ethanol by approximately 335 million gallons. Assuming ethanol is blended at 6.04 volume percent (to achieve the 2.1 weight percent oxygen required to comply under the RFG annual averaging program), this increase in ethanol use would translate to an additional 5.55 billion gallons of ethanol-blended RFG.[45] If ethanol were blended at its traditional 10 volume percent level (approximately 3.5 weight percent oxygen), the increase in ethanol-blended RFG would amount to 3.35 billion gallons.

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[45] Different bases were used to calculate the oxygenate volume required by the program (30% of the statutory minimum oxygen level of 2.0 wt%) and the amount of RFG that must be blended with renewable oxygenates (based on the minimum oxygen level required under the RFG averaging program of 2.1 wt%). Since EPA anticipates that most refiners will comply on average, the Agency based its calculation of the amount of RFG that will be blended with renewable oxygenates on the 2.1 wt% minimum oxygen requirement under averaging.

2.   Direct Costs of Additional Ethanol

     Based on current market prices, ethanol is the low-cost
oxygenate when blended into winter RFG. The cost advantage over
MTBE amounts to 0.4-1.3 cents per gallon of RFG (Regulatory
Impact Analysis for the RFG Final Rule, pp. 36-38), depending on
the market price of ethanol.[46] As a result, the 335 million
gallons of additional ethanol use stimulated by today's rule
should result in a net annual reduction in RFG costs of $22-72
million for direct oxygenate costs. EPA recognizes that market
prices for ethanol may increase during the early years of the RFG
and renewables program as demand for oxygenates in general and
renewable oxygenates in particular increases. Increases in
ethanol prices would increase the direct oxygenate costs of the
renewables program, but this increase in cost would amount to a
transfer payment from refiners, marketers, and consumers of RFG
to ethanol producers and feedstock providers. While such an
outcome would have significant income distribution consequences,
it would not directly alter the aggregate impact of the program
on the national economy.

3.   Transportation Costs

     The cost of transporting ethanol from its production
locations in the midwest to its end-use markets depends on a
number of factors. Based on information provided by the Army
Corps of Engineers,[47] the cost of transporting ethanol to RFG
markets will range from 3 to 11 cents per gallon, with an average
cost of 6-8 cents per gallon. The estimates focused on the cost
of transporting ethanol from eight existing ethanol plants to
New York either by rail or by water. The cost of shipping
ethanol by water includes the costs of rail transport to a river
port, barge transport to New Orleans, freighter transport to New
York, and the transfer of ethanol among these various
transportation modes. The Corps estimated the cost of shipping
ethanol to New York, as shown in Table IV-1 on a per-ton basis;

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[46] These cost advantages include the 54 cents per gallon
federal tax credit for ethanol use but do not include state-level
tax credits. EPA received comments arguing that the tax credit
should not be counted as a value to ethanol, but the availability
of the tax credits is likely to alter the choice of oxygenate by
refiners and blenders. The amount of tax credit involved is
presented as one of the costs of the program in section IV.E.

[47] Letter from Lloyd G. Antle, Chief, Navigation Division,
Army Corps of Engineers, to Lester Wyborny, March 23, 1994.

these estimates were converted to per-gallon estimates in Table
IV-2 (one ton of ethanol = 302.6 gallons of ethanol).

Table IV-1: Cost to Ship Ethanol to New York (per-ton basis)

Origin	Annual Tons	Rail Cost ($/Ton)	Water Cost ($/Ton)
Decatur, IL	82,349	54.37	34.70
Peoria, IL	50,722	65.11	26.60
Pekin, IL	25,361	65.46	29.83
South Bend, IN (via New Orleans)	19,020	50.48	44.98
South Bend, IN (via Great Lakes)	19,020	50.48	40.47
Cedar Rapids, IA	43,114	65.30	37.35
Clinton, IA	35,505	61.93	28.47
Blair, NE	20,288	73.59	42.24
RANGE		**50.48 - 73.59**	**26.60 - 44.98**
WEIGHTED AVERAGE		**61.18**	**33.34**

Table VI-2: Cost to Ship Ethanol to New York (per-gallon basis)

Origin	Annual Gallons	Rail Cost ($/Gallon)	Water Cost ($/Gallon)
Decatur, IL	82,349	0.180	0.115
Peoria, IL	50,722	0.215	0.088
Pekin, IL	25,361	0.216	0.099
South Bend, IN (via New Orleans)	19,020	0.167	0.149
South Bend, IN (via Great Lakes)	19,020	0.167	0.134
Cedar Rapids, IA	43,114	0.216	0.123
Clinton, IA	35,505	0.205	0.094
Blair, NE	20,288	0.243	0.140
RANGE		**0.167 - 0.243**	**0.088 - 0.149**
WEIGHTED AVERAGE		**0.202**	**0.110**

Based on this analysis, water-based transport is consistently cheaper than rail-based transport. The cost of shipping ethanol to New York by water would average approximately 11 cents per gallon. Shipping costs to other destinations are expected to be comparable. Ports in New England may involve higher direct costs because of the greater shipping distance, but ports in the mid-Atlantic states may involve correspondingly lower costs. Ports on the West Coast involve comparable shipping distances but also require passage through the Panama Canal. However, New York limits vessel cargo to 50,000 tons, while other ports allow vessels as large as 70,000 tons. These larger vessels would offer lower per-gallon ethanol shipment costs.

The Corps' analysis also suggests that ethanol shipping costs from ethanol plants to the Gulf Coast (where ethanol could be used in Texas' RFG or converted to ETBE) would be approximately 5 cents per gallon. The shipping cost to Midwestern markets such as Chicago would be approximately 3 cents per gallon. To develop an average ethanol shipping cost for the renewables program, it is necessary to project ethanol demand in the three classes of markets with different shipping costs. Based on historical market shares, EPA anticipates that ethanol-

blended RFG will achieve the largest market share in the Midwest, thereby reducing the average ethanol shipping cost to 6-8 cents per gallon. EPA's analysis of projected regional blending capacity is discussed more fully in section I.

Based on an average shipping cost of 6-8 cents per gallon, it would cost $20 million to $27 million annually to ship the additional 335 million gallons of ethanol demand resulting from the renewables program to RFG markets. It should be noted that the additional shipping costs incurred as a result of the renewables program actually would be somewhat smaller, since the costs shown above ignore the cost of shipping MTBE. EPA has been unable to quantify these costs since MTBE can be shipped directly to terminals or blended into finished gasoline at the refinery, from which it can be shipped by water, rail, tanker truck, or pipeline. However, MTBE shipping costs are expected to be relatively small.

EPA received a comment which suggested that the renewables program would require additional waterborne shipments of gasoline or blendstock. The commenter noted that as more grades of gasoline or blendstock are shipped in a pipeline, the effective capacity of the pipeline is reduced. The commenter claimed that the renewables program would add four additional grades of pipeline product. As discussed previously, however, some ethanol-blended RFG would likely be sold even in the absence of the renewable oxygenate program; in fact, several major oil companies have already announced plans to do so. Hence the fuel distribution system would have had to accommodate ethanol blendstocks absent the renewables program. The renewables program will likely increase the amount of ethanol-compatible blendstock flowing through the fuel distribution system, but it will not necessarily increase the number of blendstocks in the fuel distribution system at any one time during the year.

4.   Storage Costs

In many parts of the nation, facilities to store and blend ethanol have already been constructed. However, adequate facilities may not be in place in many RFG markets at the present time. Based on information obtained from a draft DOE report,[48]

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[48]   "Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector, Progress Report Three: Vehicle and Fuel Distribution Requirements (DRAFT)," United States Department of Energy, Office of Policy, Planning, and Analysis, July 1989.

EPA estimates the cost of building sufficient storage and blending capacity to meet the renewable oxygenate requirement to be approximately $15.6 million. DOE estimated the cost of methanol storage at $15/barrel (in 1987 dollars). Ethanol storage should be no more expensive than methanol storage on a volumetric basis and may be somewhat less expensive due to the somewhat less stringent health and safety-related handling requirements for ethanol. DOE estimated that sufficient storage needed to be available to permit 1.5 tank turnovers per month. Put differently, DOE's cost projections were based on storage capacity for 20 days' demand.

The renewables program will increase ethanol demand by approximately 335 million gallons annually, when fully phased in. This additional volume would be blended exclusively during the 6.5 months when non-VOC-controlled RFG will be in use, from late September to early April. Based on the cost analysis presented in the draft DOE report referenced above, the renewables program would require an additional $12 million in storage facilities, in 1987 dollars, or approximately $15.6 million in current dollars.

It should be noted that this figure represents a worst-case estimate of these one-time costs. To the extent that renewable MTBE or ETBE is used, the storage requirements for the renewables program would be reduced for several reasons. First, these oxygenates are likely to be blended into RFG at the refinery, where they will merely displace nonrenewable MTBE or TAME in the oxygenate storage facilities located at refineries, and will not require separate storage facilities at terminals. Second, to the extent that renewable ethers are blended at terminals, they are likely to be blended in the summer months when RVP is controlled. Ethanol storage facilities constructed to handle additional volumes of winter ethanol are likely to be unused or empty during the summer months and can be used to store renewable ethers at no additional cost.

5.   Blending Costs

EPA based its estimate of the additional costs for blending facilities on the same draft DOE report used to estimate storage costs. In that report, the cost of additional in-line blending and vapor recovery systems at terminals was estimated at $139 million to blend 730 million barrels of methanol. The renewables program will require the blending of an additional 335 million gallons (approximately 8 million barrels) of ethanol, which would involve a one-time cost of approximately $1.5 million in 1987 dollars, or approximately $2 million in current dollars. This cost estimate assumes that existing ethanol blending facilities

cannot handle any of the 335 million gallon increase in ethanol; it also ignores the possibility of utilizing truck blending. Both of these factors would tend to reduce the blending-related costs associated with the renewable oxygenate program. In addition, ethanol blending is less complex in many ways than methanol blending, on which the DOE cost analysis was based.[49]

To the extent that renewable MTBE or ETBE are used to help meet the renewables requirement, the increase in blending costs would be reduced for the same two reasons discussed above in section IV.A.4. Renewable ethers will be blended primarily at refiners in place of nonrenewable ethers and hence will entail no additional facilities or operating costs, and to the extent that renewable ethers are blended at terminals, they are likely to be blended into VOC-controlled fuel using facilities constructed to handle the blending of additional winter ethanol volumes that otherwise would tend to be idle during the VOC control season.

6. Toxics Compliance Costs

On a per-unit-oxygen basis, ethanol and ETBE provide smaller toxics emission reductions than do MTBE or TAME, according to both the Simple and Complex Models. Since the toxics performance standards are not changed by the renewables rule, some refiners therefore may face higher toxics compliance costs as a result of the substitution of ethanol or ETBE for MTBE or TAME under the renewables program. Not all refiners will experience such increased costs, however, for several reasons. First, refiners with relatively low baseline aromatics levels (under the Simple Model) or low baseline levels of sulfur, olefins, or aromatics (under the Complex Model) may be able to comply with the toxics performance requirements, even with the reduced toxics benefits resulting from increased ethanol or ETBE use, without undertaking any additional fuel modifications. The toxics emission benefits they achieve would be reduced as a result of complying with the renewables requirements, but they would still meet the RFG toxics performance standards. Second, some refiners may have the technological flexibility to reduce aromatics levels without incurring additional costs. In fact, some refiners may actually be able to reduce their aromatics levels and costs simultaneously by reducing their reformer severity while still maintaining the octane level of their fuel.

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[49] One of the reasons why ethanol blending is less complex than methanol blending is that ethanol is not as hazardous or toxic a substance as methanol.

However, some refiners may lack the technological capability
to simultaneously balance octane demand and toxics performance
without incurring higher costs. Other refiners with high
baseline levels of aromatics, olefins, or sulfur may not have
"surplus" toxics emission reductions; for such refiners, the loss
of toxics performance associated with switching from MTBE or TAME
to ethanol or ETBE may require changes in refinery configurations
or operations, both of which may be costly.

The analysis required to evaluate the toxics compliance cost
impact of the renewable oxygenate program consists of five steps.
First, EPA defined the fuels to be evaluated in terms of their
Simple and Complex Model properties. Second, EPA further
constrained the fuels in question by octane-matching the fuels.
Third, EPA evaluated the toxics emission performance of the fuels
defined in steps one and two. Fourth, EPA determined the least-
cost means by which the ethanol and ETBE fuels could be modified
to achieve the required toxics performance under the RFG program.
Fifth, EPA determined the least-cost means by which the ethanol
and ETBE fuels could be modified to achieve the same toxics
performance as was achieved by the MTBE fuels. EPA based its
analysis on the performance of fuels with industry-average levels
of the relevant fuel parameters because the annual averaging and
nationwide trading provisions of the renewables program
effectively creates a single nationwide gasoline pool for the
purposes of complying with the requirements of the renewables
rule.

In step one, EPA defined a number of oxygenate scenarios to
quantify the additional toxics costs, if any, resulting from the
renewable oxygenate program. EPA's short-term scenario compared
the performance of MTBE blends with ethanol blends under winter
conditions according to the Simple Model. EPA's longer term
scenario compared MTBE-based blends with ethanol-based and ETBE-
based blends in the winter and with ETBE-based blends in the
summer.

In step two, EPA determined the aromatics level for fuels
under each scenario defined in step one. EPA assumed that
refiners would try to assure that their RFG blends met a target
octane level. Octane is valuable, so EPA believes it is unlikely
that refiners would give octane away for free. Rather, refiners
are likely to optimize the properties of their blendstocks and
fuels to meet the RFG emission requirements at various target
octane levels (depending on the grade of gasoline involved).
EPA's analysis assumed that all blends would meet a target octane
level of 88.5, which is approximately equal to the average octane
in the U.S. gasoline pool. To meet this target octane level,

refiners would need to manage the levels of three major
components of RFG: the oxygenate type and level, the aromatics
level, and the level of the remaining hydrocarbons in gasoline.
The levels of these three components would have to satisfy the
following equation:

$$(ON) = xX + aA + rR,$$

where
  a = Aromatics concentration in finished RFG
  A = Octane value of the aromatics
  ON = The target octane number
  r = Remaining hydrocarbons' concentration in finished RFG
  R = Octane value of the remaining hydrocarbons
  x = Oxygenate concentration of finished RFG
  X = Octane value of the oxygenate

For the purposes of this analysis, EPA assumed that each
oxygenate would be blended at a level equivalent to 2.1 weight
percent oxygen, which translates into an MTBE concentration of
11.55 percent, an ethanol concentration of 5.77 percent, and an
ETBE concentration of 13.2 percent. EPA also assumed that the
aromatics stream had an octane value of 130, in accordance with
standard industry practice.

      EPA then calculated the octane value of the remaining
hydrocarbons by solving the equation presented above for 1990
industry-average gasolines. The summer baseline gasoline had an
aromatics level of 32 percent in the summer, an oxygenate level
of zero percent, an octane level of 88.5, and a remaining
hydrocarbons level of 68 percent. The winter baseline gasoline
had an aromatics level of 26.4 percent, an oxygenate level of
zero percent, an octane level of 88.5, and a remaining
hydrocarbons level of 73.6 percent. Solving the equation
presented above for these two gasolines yields an octane value
for the remaining hydrocarbons of 69 in summer gasoline and 73.6
in winter gasoline; the difference is likely due to the lower
level of butane (which has a relatively high octane value) in
summer baseline fuel for RVP control reasons. This value was
used for all subsequent calculations, in which the level of
aromatics was varied to achieve the target octane value of 88.5.
Standard octane values of 110 for MTBE, 115 for ethanol, and 112
for ETBE were used throughout the analysis. The results of these
calculations are summarized in Table IV-3.

Table IV-3: Octane Matching Fuel Scenarios

Fuel Scenario (Season & Oxygenate)	Oxygenate (Volume % @ Octane Value)	Aromatics (Volume % @ Octane Value)	Remaining hydrocarbons (Volume % @ Octane Value)
Summer baseline	None	32.0% @ 130	68.0% @ 69
Summer MTBE	11.54% @ 110	24.21% @ 130	63.45% @ 69
Summer ETBE	13.38% @ 112	22.54% @ 130	64.08% @ 69
Winter baseline	None	26.4% @ 130	73.6% @ 73.6
Winter MTBE	11.55% @ 110	19.00% @ 130	69.45% @ 73.6
Winter ethanol	6.04% @ 115	22.18% @ 130	72.05% @ 73.6
Winter ETBE	13.38% @ 112	17.31% @ 130	69.31% @ 73.6

EPA then calculated the toxics performance of the oxygenated fuel scenarios described above, under both the simple and complex models. In performing these calculations, the following fuel parameter values were used:

Table IV-4: Octane-Matched Phase I Fuels

Parameter	Summer MTBE	Summer ETBE	Winter MTBE	Winter ethanol	Winter ETBE
Oxygen, wt%	2.1	2.1	2.1	2.1	2.1
Sulfur, ppm	339	339	338	338	338
RVP, psi	7.1/8.0	7.1/8.0	N/A	N/A	N/A
E200	46.0	47.0	54.5	52.3	56.0
E300, vol%	85	85	83.7	83.7	83.7
Benzene, vol%	0.95	0.95	0.95	0.95	0.95
Olefins, vol%	13.1	13.1	11.9	11.9	11.9
Aromatics, vol%	24.21	22.54	19.00	22.18	17.31

The aromatics levels in the fuels in Table IV-4 were determined through the octane matching process discussed above. The RVP, oxygen, and benzene levels were set at the limits defined in the RFG final rule for compliance on average, since EPA anticipates that most refiners will comply on this basis. Olefins, E300, and sulfur are capped at each refiners' 1990 baseline level under the Simple Model; as a result, the olefin, E300, and sulfur levels of the fuels in Table IV-4 were set at the 1990 industry-average levels for summer and winter, respectively. E200 is not constrained under the Simple Model and was allowed to change from its industry-average level based on a simple dilution model.

Applying the same methodology to Phase II fuels is more difficult, since the composition of such fuels may vary more widely. In particular, the sulfur level that refiners achieve depends strongly on their aromatics and olefin levels. The primary reason for reducing sulfur is to reduce NOx emissions. Sulfur reductions also help reduce toxic emissions, so some refiners may be able to rely on sulfur reductions to offset the increase in toxics emissions resulting from greater ethanol and ETBE use. However, most of the cost of sulfur reduction involves operating cost, which suggests that most refiners are likely to avoid de-sulfurizing their non-VOC-controlled fuel, since NOx reductions are not required in the winter months. As a result, winter sulfur levels in the Phase II fuels described in Table IV-5 were left at baseline levels. Summer RVP levels were set at the nominal level used by EPA to set the Phase II emission

standards, and E200 levels were adjusted to reflect the change in
RVP levels. Other parameters remain unchanged from the Phase I
levels presented in Table IV-4.

Table IV-5: Octane-Matched Phase II Fuels

Parameter	Summer MTBE	Summer ETBE	Winter MTBE	Winter ethanol	Winter ETBE
Oxygen, wt%	2.1	2.1	2.1	2.1	2.1
Sulfur, ppm	134	134	338	338	338
RVP, psi	6.7	6.7	N/A	N/A	N/A
E200	44.0	45.0	55.0	52.3	56.0
E300, vol%	85	85	83.7	83.7	83.7
Benzene, vol%	0.95	0.95	0.95	0.95	0.95
Olefins, vol%	13.1	13.1	11.9	11.9	11.9
Aromatics, vol%	24.21	22.54	19.00	22.18	17.31

Before discussing the performance of these fuel scenarios,
it is important to note that the properties of actual RFG fuels
may differ considerably from the properties shown above. For
example, greater or lesser levels of aromatics may be present in
real RFG blends. Similarly, different oxygen levels may exist in
commercial RFGs. For example, some reformulated gasolines may be
blended with 10 volume percent ethanol and therefore would
contain 3.5 weight percent oxygen. EPA chose not to analyze the
toxics implications of ethanol blending at 10 volume percent for
several reasons. First, such blending levels would generate
oxygen credits under the RFG program that could be used to reduce
the amount of oxygenates (such as MTBE) blended in other volumes
of RFG. Compliance considerations suggest that such credits
would be limited in usefulness to the RFG market in which they
are generated. These factors make it difficult to forecast the
precise impact of ethanol blending at 10 volume percent on the
composition and toxics emission performance of RFG on both a
market-specific and nationwide basis. Second, ethanol is
typically blended at 10 percent at terminals in order to take
full advantage of State and federal tax credits and hence is
generally splash blended into unmodified blendstock. The toxics
performance of RFG splash-blended with ethanol at 10 percent is

difficult to forecast since it is difficult to determine the properties of the blendstocks with which it will be blended, particularly in the winter months when the RVP of the finished gasoline is not controlled by the RFG program. Furthermore, the nature of splash blending implies that the fuel is not octane-matched, as is the case for the scenarios analyzed below. The aromatics level of the splash blend likely would be approximately equal to that of the MTBE blend and would have a toxics performance level several percentage points poorer than the toxics performance of the MTBE blend. Third, the analysis contained in this section is intended to represent the average performance of the gasoline pool; to the extent that some gallons are blended with 3.5 weight percent oxygen in the form of ethanol, other gallons would be blended with lower levels of oxygen, and the overall toxics compliance impact on the nationwide RFG gasoline pool would be unchanged. Fourth, while ethanol may be blended in concentrations as high as 3.5 weight percent oxygen, the RFG program requires only a 2.1 weight percent oxygen concentration on average. Fifth, a direct comparison of the toxics performance of different oxygenates is most usefully made when as many factors as possible are kept constant. In this analysis, EPA chose to keep oxygen concentration and octane constant. And as discussed elsewhere in this section, these scenarios permit reasonable estimates of the range of likely effects of the renewables program on toxics emissions and toxics compliance costs. Sixth, an octane-matching scenario for 10 percent ethanol blends would require aromatics levels to be in the 14 percent range. This level of aromatics is at the low end of the range of aromatics levels found in in-use fuels, including 10 percent ethanol blends and is in the range of values where the Complex Model must be extrapolated in order to estimate emissions. EPA considers 14 percent aromatics fuels to be extreme in their composition and properties and does not consider such fuels to represent a realistic basis for average in-use reformulated gasolines. Furthermore, EPA recognizes that such low aromatics levels would create shortages of hydrogen for many, if not most, refineries.

The performance of the fuels presented in Tables IV-4 and IV-5 under the Simple and Complex Models are summarized in Table IV-6.

Table IV-6: Toxics Performance of Octane-Matched Fuels
(percent reduction from baseline)

Model/Phase/ Region[1/]	Summer MTBE	Summer ETBE	Winter MTBE	Winter ethanol	Winter ETBE
Simple/I/1	27.1	26.0	21.6	15.9	21.7
Simple/I/2	24.0	22.7	21.6	15.9	21.7
Complex/I/1	29.74	26.77	20.35	14.41	16.37
Complex/I/2	26.24	22.89	20.35	14.41	16.37
Complex/II/1	27.96	25.02	20.94	15.08	17.15
Complex/II/2	27.57	24.62	20.94	15.08	17.15

[1/]Region refers to the VOC control region; see the RIA for the RFG final rule for further discussion of VOC control regions.

Several different scenarios are of particular interest in analyzing the effect of the renewables requirement on toxics compliance costs. The base case would rely on MTBE in both summer and winter. The ethanol case would rely on MTBE in summer RFG and ethanol in winter RFG. The ETBE case would rely on ETBE in both summer and winter. Finally, the ETBE/ethanol case would rely on ETBE in summer and ethanol in the winter. The annual average toxics performance for these cases is presented in Table IV-7, based on 60.4% of the RFG being non-VOC controlled winter fuel and 39.6% of the RFG being VOC-controlled summer fuel.[50] As discussed elsewhere, VOC-controlled fuel may comprise a larger fraction of the total amount of RFG produced since refiners must ship such fuel sufficiently early to assure turnover at retail stations by June 1. Table IV-6 indicates that the toxics performance of VOC-controlled (summer) fuel is superior to that of non-VOC-controlled (winter) fuel, so to the extent that VOC-controlled fuel comprises more than 39.6% of total RFG production, annual average toxics performance would be improved beyond the levels shown in Table IV-7 and any additional toxics compliance costs associated with greater ethanol or ETBE use would be reduced.

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[50] The summer proportion is equal to the proportion of fuel sold in the months when VOC-controlled RFG is required at terminals (May 1 - September 15).

Table IV-7: Annual Average Toxics Performance For Octane-Matched Fuel Scenarios (percent reduction from baseline)

Model/Phase/ Region	MTBE/MTBE Case	MTBE/ Ethanol Case	ETBE/ETBE Case	ETBE/ Ethanol Case
Simple/I/1	23.8	20.3	23.4	19.9
Simple/I/2	22.5	19.1	22.1	18.6
Complex/I/1	23.67	19.82	20.04	18.78
Complex/I/2	22.40	18.53	18.64	17.36
Complex/II/1	23.18	19.20	19.66	18.26
Complex/II/2	23.05	19.05	19.52	18.11

Three key points should be noted from the preceding table. First, all of the oxygenated fuels offer greater toxics reductions than required by the Phase I RFG requirements. Second, the only Phase II scenario that meets the 21.5% annual average standard for toxics reduction is the MTBE/MTBE case. Third, the ethanol and ETBE fuels consistently yield poorer toxics performance than the MTBE fuels. The first point indicates that the renewable oxygenate program may not entail any additional toxics compliance cost in Phase I for the average refiner, since octane matching considerations alone are sufficient to assure that ethanol and ETBE-blended RFGs will meet the Phase I toxics requirements under both the Simple and Complex Models. The second point indicates that the renewable oxygenate program will entail some additional costs for toxics compliance during Phase II of the RFG program. The third point indicates that increased use of renewable oxygenates may reduce the toxics benefits of RFG relative to what would have occurred without the renewables program, though it should be noted that refiners would still be required to meet the toxics performance standards specified in the RFG final rule. As a result, those refiners whose initial aromatics levels are higher than the Clean Air Act baseline level may face additional toxics compliance costs during both phases.

The cost of restoring the toxics performance of the MTBE/MTBE case in Phase I depends on the approach chosen to reduce toxics. Under the simple model, the only choices available to refiners are RVP, oxygen, benzene, and aromatics. Of these choices, benzene and aromatics offer the most cost-

effective toxics reductions.[51] Under the complex model, benzene offers the most cost-effective toxics reductions. The cost of aromatics reduction was estimated at 0.4 cent per gallon for each one percentage point reduction in aromatics. The cost of benzene reduction was estimated at 0.3 cent per gallon to reduce fuel benzene from 1.0 to 0.8 volume percent and at 0.5 cent per gallon to reduce benzene from 0.8 to 0.6 volume percent. Based on these values, the per-gallon cost of restoring toxics performance to the level achieved in the MTBE/MTBE case for each alternative scenario is summarized in Table IV-8.

Table IV-8: Cost to Recoup Reduction in Annual Average Toxics Performance From MTBE/MTBE Base Case (cents per gallon)

Model/Phase/ Region	MTBE/Ethanol Case	ETBE/ETBE Case	ETBE/Ethanol Case
Simple/I/1*	0.75 - 1.30	0.06 - 0.16	0.85 - 1.48
Simple/I/2*	0.675 - 1.28	0.06 - 0.16	0.775 - 1.48
Complex/I/1*	0.89 - 2.27	0.73 - 2.51	1.06 - 3.21
Complex/I/2*	0.89 - 2.27	0.74 - 2.62	1.05 - 3.32
Complex/II/1	0.88	0.84	1.11
Complex/II/2	0.88	0.84	1.11

*   Lower end of the range represents cost of benzene reductions, higher end represents cost of aromatics reductions

When these costs are multiplied by the 5.55 billion additional gallons of RFG that would be blended with renewable oxygenates (at 2.1 weight percent oxygen) as a result of the renewables program, the total cost to recoup the reduction in annual average toxics performance is as shown in Table IV-9 below. (If ethanol were blended at 3.5 weight percent oxygen, fewer gallons of RFG would need to be blended but the per-gallon toxics effects would be proportionately greater.)

     It should be noted that the added cost of meeting the toxics standards may be considerably smaller than the figures shown in Table IV-9 for three reasons. First, as discussed previously, not all refiners will need to recoup the entire loss in toxics

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[51]   See the RIA for the final RFG rule.

performance resulting from the increased use of renewable oxygenates in order to meet the RFG toxics standards. Second, to the extent that ETBE would be used in RFG in the absence of the renewables requirement, the additional costs for the ETBE/ETBE and ETBE/Ethanol cases would be reduced. Third, refiners would not suffer any degradation in the toxics performance of their fuels to the extent they meet the renewables requirement with renewable MTBE.

Table IV-9: Total Cost to Recoup Reduction in Annual Average Toxics Performance From MTBE/MTBE Base Case ($ million/year)

Model/Phase/ Region	MTBE/Ethanol Case	ETBE/ETBE Case	ETBE/Ethanol Case
Simple/I/1*	41.63 - 72.15	3.33 - 8.88	47.18 - 82.14
Simple/I/2*	37.46 - 71.04	3.33 - 8.88	43.13 - 82.14
Complex/I/1*	49.40 - 125.99	40.52 - 139.31	58.83 - 178.16
Complex/I/2*	49.40 - 125.99	41.07 - 145.41	58.28 - 184.26
Complex/II/1	48.84	46.62	61.61
Complex/II/2	48.84	46.62	61.61

*   Lower end of the range represents cost of benzene reductions, higher end represents cost of aromatics reductions

     The costs shown above tend to overstate the increase in toxics compliance costs attributable to the renewables program in several important ways. First, the costs are based on the assumption that refiners must fully recoup any reduction in toxics performance. However, as shown in Table IV-7, it is likely that many refiners will produce fuels whose toxics performance exceed the standard by a significant margin, particularly in Phase I. Such refiners need not recoup the entire reduction in toxics resulting from substitution of ethanol or ETBE for MTBE. To quantify the resulting impact on cost, EPA calculated the cost of bringing all of the fuel scenarios presented above into compliance with the relevant toxics standard (16.5% reduction in Phase I and 21.5% reduction in Phase II). The only cases which do not meet the nominal standards are the Phase II cases. The costs for these cases are shown in Table IV-10.

Table IV-10: Cost to Meet Nominal Annual Average Toxics Standard
(cents per gallon)

Model/Phase/ Region	MTBE/Ethanol Case	ETBE/ETBE Case	ETBE/Ethanol Case
Simple/I/1	0.00	0.00	0.00
Simple/I/2	0.00	0.00	0.00
Complex/I/1	0.00	0.00	0.00
Complex/I/2	0.00	0.00	0.00
Complex/II/1	0.32	0.40	0.71
Complex/II/2	0.34	0.44	0.76

When these costs are multiplied by the 5.55 billion additional gallons of RFG that would be blended with renewable oxygenates at 2.1 weight percent oxygen as a result of the renewables program, the total cost to meet the nominal toxics standard would be as shown in Table IV-11. If ethanol were blended at higher concentrations, the number of gallons involved would be smaller but the per-gallon impact would be proportionately larger.

Table IV-11: Total Cost to Meet the Nominal Annual Average Toxics Standard ($ million/year)

Model/Phase/ Region	MTBE/Ethanol Case	ETBE/ETBE Case	ETBE/Ethanol Case
Simple/I/1	0.00	0.00	0.00
Simple/I/2	0.00	0.00	0.00
Complex/I/1	0.00	0.00	0.00
Complex/I/2	0.00	0.00	0.00
Complex/II/1	17.76	22.22	39.40
Complex/II/2	18.87	24.42	42.18

Even these latter cost estimates may overstate the cost of toxics compliance. To the extent that refiners would have utilized ETBE during Phase II of the RFG program in the absence

of the renewables program, some of the additional toxics
compliance costs included in the foregoing Phase II cost
estimates would have been incurred without the renewable
oxygenate requirement. However, EPA is unable to quantify the
amount of ETBE that would have been used in Phase II if the
renewables rule were not in place. As a result, EPA has based
its estimates of the total toxics compliance costs for the
renewables program on the assumption that winter ethanol will be
used to meet the renewables requirement in both Phase I and Phase
II. To the extent that additional ETBE use is required to meet
the renewables requirement, toxics compliance costs would be
significantly larger. However, to the extent that ETBE would
have been used to meet the RFG program requirements independent
of the renewables requirement, toxics compliance costs would be
reduced. Note that this assumption ignores the possibility that
MTBE produced from renewable methanol could be used to help
satisfy the renewables requirement; since the MTBE blends offer
superior toxics performance, the availability of renewable MTBE
would further reduce the toxics compliance costs. Subject to
these caveats and the caveat that increased production of VOC-
controlled RFG would improve toxics performance and reduce toxics
compliance costs, EPA has estimated the annual toxics compliance
cost for the renewables program as shown in Table IV-12. The
estimates in Table IV-12 incorporate the full range of potential
toxics costs, with the low end of the range based on the cost of
meeting the nominal toxics standard and the high end of the range
based on the cost of recouping any loss in toxics performance.
The estimates in Table IV-12 assume that benzene reductions are
used to achieve any necessary toxics reductions.

Table IV-12: Total Toxics Compliance Costs, ($ million/year)

Model/Phase/ Region	MTBE/Ethanol Case	ETBE/ETBE Case	ETBE/Ethanol Case
Simple/I/1	0.00 - 41.63	0.00 - 3.33	0.00 - 47.18
Simple/I/2	0.00 - 37.46	0.00 - 3.33	0.00 - 43.13
Complex/I/1	0.00 - 49.40	0.00 - 40.52	0.00 - 58.83
Complex/I/2	0.00 - 49.40	0.00 - 41.07	0.00 - 58.28
Complex/II/1	17.76 - 48.84	22.20 - 46.62	39.40 - 61.61
Complex/II/2	18.87 - 48.84	24.42 - 46.62	42.18 - 61.61

EPA considers the MTBE/ethanol case the most likely, particularly during the early years of the program. As a result, the total cost for toxics compliance resulting from the renewables rule has been estimated to range from zero to $49 million during Phase I and from $18 million to $49 million during Phase II.

7.   Additional ETBE Costs

EPA estimated ETBE costs relative to MTBE costs in the RIA for the RFG final rule. These estimates range from zero additional cost to an additional cost of 0.8 cent per gallon of RFG blended with ETBE, including both capital and operating costs. It should be noted that the ETBE costs presented in the RFG RIA assumed that the ethanol tax credit would be available for ETBE, based on the amount of ethanol used to produce each gallon of ETBE. However, EPA received comments, from Arco Chemical among others, which noted that under the current tax structure, ETBE producers and blenders may not be able to obtain comparable tax credits. Without the tax credit, each gallon of RFG blended with ETBE (at 2.1 wt% oxygen) could cost as much as 3.1 to 3.9 cents per gallon more than MTBE-blended RFG. At the same time, the expanded ethanol capacity stimulated by the renewables program may reduce the cost of summer ethanol sufficiently to offset a considerable amount of this cost disadvantage.

EPA received a comment which stated that the operational difficulties associated with converting from ETBE use in the summer to ethanol use in the winter would tend to force refiners to blend ETBE year-round, thereby making the renewables program an ETBE mandate. EPA has not received adequate information to justify this conclusion, particularly given the large cost advantage of ethanol over ETBE (per unit oxygen) during the winter. However, EPA acknowledges that some refiners may experience additional expense in converting from ethanol use to ETBE use. EPA believes that by promulgating an annual average program (rather than a seasonal averaging program as suggested by USDA and as discussed in more detail in section V), the potential adverse economic effects of the renewables program are minimized.

8.   Fuel Economy Costs

Based on EPA's analysis of the fuel economy effects of RFG (see the RIA for the RFG final rule), ETBE and MTBE blended fuels achieve almost identical fuel economy on a per-gallon basis. The same is not true for ethanol fuels, whose fuel economy is approximately 0.2 percent less than that of MTBE-blended fuels due to the slightly smaller energy content of ethanol-blended fuels. Based on the additional 5.55 billion gallons of RFG that would be blended with ethanol (at 2.1 weight percent oxygen, or 5.77 volume percent ethanol) as a result of the renewables program, this fuel economy penalty translates to an increase in fuel volume of approximately 11.1 million gallons. Given a wholesale price for gasoline of approximately $0.50, the loss in fuel economy adds $5.55 million to the cost of the program.

To the extent that ETBE is used to satisfy the renewables requirement, this cost would be reduced. In particular, the fuel economy cost during Phase II would likely be considerably smaller since the Phase II VOC standards are likely to stimulate more widespread ETBE use. In estimating the cost of the renewables program, however, EPA did not assume any increase in ETBE use during Phase II solely as a result of the renewable oxygenate requirement.

9.   Summary of Fuel and Blendstock Costs

The annual fuel and blendstock-related costs of the renewables program are summarized in Table IV-13.

Table IV-13: Annual Fuel and Blendstock Costs for the Renewable Oxygenate Program[*]

Cost Category	Phase I Cost Range	Phase II Cost Range
Oxygenate	($22 - 72 million)	($22 - 72 million)
Transportation	$20 - 27 million	$20 - 27 million
Toxics Compliance	$ 0 - 49 million	$18 - 49 million
Fuel Economy	$ 6 million	$ 6 million
Total Annual Costs	$ 4 - 60 million	$22 - 60 million

 [*] Assuming that direct oxygenate savings are at the low end of the range. If direct oxygenate savings are larger than the

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minimum, the total annual cost of the program would be reduced.

In addition to these annual costs, the program would entail one-time costs for additional storage facilities of approximately $15.6 million and for additional blending capacity of approximately $2 million. It should be noted that the costs in 2000 and beyond are likely to be smaller than the costs presented in Table IV-13 since significant amounts of ETBE likely would have been used in the absence of the renewables program.

10. Additional Comments

EPA received a comment which recommended that EPA evaluate the reduction in gross domestic product resulting from the indirect effects of intervening in the fuels market. The Agency acknowledges that such an analysis would be desirable. However, EPA does not have sufficiently detailed information to conduct such an analysis, and the comment was not accompanied by sufficient information to remedy this problem. In addition, the existing state of econometric modeling is not sufficiently precise and accurate to allow such an analysis to be performed reliably. Furthermore, such an analysis should include consideration of other indirect effects of the renewables rule, such as its impact on renewable fuel production technology.

EPA received a number of comments estimating the cost of one aspect or another of the renewable oxygenate program. Many of these comments contained insufficient detail to allow EPA to assess their basis, relevance, and accuracy. For example, one commenter claimed that the renewables program would cost $200,000 per terminal for additional tankage and blending capacity, but did not provide information regarding the assumed ethanol volumes and existing tankage and blending capacity. EPA believes that the foregoing analysis provides a reasonable estimate of the costs of the renewables program.

B.   Impact on Renewables Industry

The renewable oxygenate program is expected to have a number of beneficial effects on the renewable fuels industry. First, it will prevent a supply disruption in the several major existing ethanol markets affected by the RFG program. In particular, the renewables program will create incentives to continue blending ethanol in non-summer gasoline in the Northeast, Milwaukee, and Chicago. The amount of ethanol blended into gasoline in these markets in 1993 (presented in Table IV-14 below) equals approximately 19% of total U.S. fuel ethanol consumption. In the absence of the renewables program, the RFG program's limits on RVP (in summer gasoline) may make it difficult to procure appropriate blendstocks for ethanol blending in these major ethanol markets. Further, the difficulties associated with switching between ethanol and non-ethanol blends may limit ethanol use in winter gasoline in these areas.

Table IV-14:   Ethanol Use in Selected RFG Markets[52]

Market	1993 Ethanol Use in Winter (MM gallons)	1993 Ethanol Use in Summer (MM gallons)	1993 Total Ethanol Use (MM gallons)
Chicago	49.2	44.9	94.1
Milwaukee	3.3	1.9	5.2
Northeast[53]	91.0	42.9	133.8
Total	143.5	89.6	233.1

Second, the renewables program will provide greater certainty regarding demand for ethanol, thereby reducing the risks associated with investments in ethanol production facilities. The amount of investment capital involved is significant. The Governors' Ethanol Coalition claimed in comments submitted to EPA that the renewables program would result in $1-3 billion in capital investments.

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[52]   Based on data submitted by Information Resources, Inc., as summarized in Appendix 1.

[53]   Includes all members of the Ozone Transport Commission.

Third, the renewables program will stimulate substantial growth in the renewables industry. As discussed in section IV.A.1, the renewables program is anticipated to result in a 335 million gallon increase in annual ethanol usage. This growth amounts to an increase of approximately 28% from 1993 levels (see section I.D for details).

EPA received many other comments discussing the impact of the renewable oxygenates program on the renewable fuels industry. Most of these comments noted the favorable impact that the proposed renewable oxygenate program would have on this industry. For example, EPA received comments which noted that a number of innovative renewable oxygenate production processes existed, including processes to produce ethanol or methanol from cellulosic materials, and that development and commercialization of these processes would be enhanced by implementation of the renewables program. Many of these comments presented estimates of the number of jobs that would be created as a result of increased renewable oxygenate production. However, these estimates did not quantify the reduction in employment growth in the nonrenewable oxygenate industry as a result of the renewables program. EPA acknowledges that some jobs will be created and others will fail to materialize as a result of the renewables program, but the Agency does not have sufficient information or expertise to forecast the program's overall employment impact.

EPA also received several comments that a number of processes for producing renewable oxygenates other than ethanol, notably renewable methanol for MTBE production, were near commercialization. These comments argued that the renewables program would provide the market stability and economic incentives needed to commercialize these processes. EPA is not able to forecast the impact of the renewables program on the prospects for these processes with certainty but agrees that the renewables program will provide incentives to help commercialize these alternative renewable oxygenate incentives.

C.   Impact on Farm Economy

EPA received numerous comments regarding the potential benefits and costs of the renewables program to farmers, the agricultural sector in general, and rural economies. Benefits and costs mentioned in the comments included increased farm incomes from higher crop prices and/or increased crop demand, increased investment in and employment at ethanol production facilities, and increased costs for livestock producers as a result of higher feed costs. The range of projected costs and benefits varied widely, and in most cases the estimates did not examine benefits and costs relative to what would occur in the absence of the program.

According to comments submitted by a number of agricultural industry associations and USDA, approximately 2.5 gallons of ethanol can be produced from a single bushel of corn. Based on comments received from USDA, each 100 million bushel increase in corn demand results in a 3-5 cent per bushel increase in corn prices. Based on these figures, the 335 million gallon increase in ethanol demand resulting from the renewables program would increase corn demand by 134 million bushels and thereby increase corn prices by 4.0-6.7 cents per bushel. This increase in corn prices would increase farm incomes significantly. Based on an average corn crop of 8.7 billion bushels,[54] the price increase resulting from the renewable oxygenate program would increase farm incomes by $348-583 million annually. This increase in farm incomes from crop production would, according to USDA, reduce farm deficiency payments by $220-$369 million annually,[55] so the total increase in farm income would amount to $128-214 million annually. In addition, much of the increase in crop prices would increase costs for other sectors of the economy or to consumers and hence represents a transfer of income rather than a genuine increase in national income. The reduction in farm deficiency payments would reduce federal outlays on a dollar for dollar payment.

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[54] According to information provided by John W. McClelland of USDA, "Memorandum for Richard Wilson, Director, Office of Mobile Sources, U.S. Environmental Protection Agency," June 20, 1994.

[55] According to USDA, 5.5 billion bushels of annual corn production are eligible for deficiency payments. These payments would be reduced by the 4.0-6.7 cents per bushel increase in corn prices. John W. McClelland of USDA, "Memorandum for Richard Wilson, Director, Office of Mobile Sources, U.S. Environmental Protection Agency," June 20, 1994.

EPA received larger and smaller estimates of the potential increase in farm incomes. Most of the differences involved different estimates of the increase in corn demand resulting from the renewables program. Some commenters noted that a number of oil companies previously had announced plans to rely on ethanol for a substantial part of their oxygenate requirement. Others noted that ethanol's price advantage (on a weight percent oxygen basis) would result in its widespread use even without the renewables program. These two groups of commenters argued that the renewables program would not stimulate greater demand for corn than would have occurred in the absence of the 30 percent renewables requirement. On the other hand, many commenters projected that no ethanol would be used in RFG without the renewables program. These commenters credited the renewables program for stimulating corn demand to supply the entire 670 million gallons of ethanol required to fulfill the 30 percent requirement. Some of these commenters maintained that the 670 million gallons of ethanol demanded by the renewables program could be met with existing capacity and would simultaneously stimulate increased demand for corn; EPA's analysis recognizes that ethanol diverted from existing markets would not result in increased corn demand. Other commenters credited the renewables program with stimulating ethanol capacity under construction prior to the renewable oxygenate proposal (and increasing demand for corn as a result); EPA's analysis recognizes that such projects were undertaken for reasons other than to meet the needs of a renewables program that had not even been proposed at the time construction began.

Some commenters predicted larger price increases from increased corn demand than did USDA. For example, comments received from the Illinois Corn Growers estimated that each 100 million bushel increase in corn demand would increase corn prices by 6 cents per bushel. The Iowa Department of Economic Development estimated that a 100 million bushel increase in corn demand would increase corn prices by 8 cents per bushel. Still other commenters such as Hertz Farm Management predicted a reduction in corn prices by 5 cents per bushel as the Midwest recovers from the 1993 floods and noted that the renewables program could help offset this decrease by increasing prices through increased demand. EPA acknowledges that the actual price of corn may fluctuate from a number of factors, but these fluctuations do not alter the conclusions reached by USDA that an increase in ethanol demand would increase demand for corn and thereby boost per-bushel corn prices relative to what those prices would have been in the absence of the renewable oxygenate program. EPA acknowledges that none of the projected increases in corn prices (or the resulting increases in farm income and

decreases in deficiency payments, discussed in section IV.F) would occur if the 30 percent renewables requirement were met by diverting ethanol from existing markets to RFG markets, but notes that the renewables program is designed to permit the renewables requirement to be met without diverting ethanol from existing markets by phasing in the full 30 percent requirement over two years.

The income benefits from corn price increases may be offset by reduced income for other agricultural sectors, notably livestock and dairy producers. However, the additional costs to livestock producers (estimated by Mark Peters of USDA's Economic Research Service to be 82% of the increased crop sector revenues, according to comments submitted by the Illinois Farm Bureau) may be offset by several factors. In the short run, increased output of corn byproducts such as corn gluten feed (CGF) as a result of increased ethanol production may reduce corn gluten feed prices and thereby lower livestock producers' costs. Without detailed information on price elasticities, ease of substitution between CGF and corn in livestock operations, and the relative importance of CGF and corn in livestock operations, it is difficult to determine the degree to which CGF price reductions would offset direct corn price increases for livestock producers. However, one simplifying factor is that the market price for corn will tend to reflect reductions in the value of corn byproducts; as a result, corn prices will tend to fall if increased CGF production suppresses CGF prices. As a result, any savings to livestock producers resulting from CGF price decreases will tend to be offset by the reduction in farm income resulting from reduced corn prices. In the longer run, the introduction of cellulose-based ethanol production processes will allow farmers to reap higher prices for corn without increasing the cost to corn consumers, including livestock producers, as agricultural wastes with little current value become valuable in their own right.

EPA received comments noting that increased ethanol production would increase production of byproducts such as CGF. The comments received suggested that the increase in byproduct output would be exported and would not depress domestic prices for the byproducts. EPA is not able to evaluate all of the impacts of an increase in byproduct output at this time, but it is reasonable to expect that such an increase would result in some increase in exports and some decrease in domestic byproduct prices. EPA is unable to calculate the relative impact of these changes at this time.

D.   Impact on Natural Gas, Methanol, and MTBE Sectors

     A number of commenters noted that the renewables program
would adversely affect MTBE producers and their suppliers in the
natural gas and methanol industries. The renewables program is
expected to reduce MTBE demand by 638 million gallons annually,
methanol demand by 217 million gallons annually, and natural gas
demand by 15.9 billion cubic feet annually, assuming that both
the methanol and isobutylene used to produce MTBE is derived from
natural gas. Some of the reduction in natural gas demand would
be offset by increased ETBE production, which was also assumed to
utilize isobutylene produced from natural gas.

     It should be noted that these reductions in demand will not
reduce absolute demand for MTBE, methanol, or natural gas from
current levels. Demand for these products is expected to grow
substantially as the RFG program is implemented. If ethanol
supplies the entire 30 percent renewable oxygenate requirement,
most of the oxygenates used in RFG still would be derived from
nonrenewable sources. If MTBE supplies the remaining 70% of the
RFG oxygenate requirement, and if (as expected) refiners comply
with the RFG oxygen requirement on an annual average basis,
annual MTBE demand is projected to grow by 109% from its 1993
level of 2.3 billion gallons to 4.8 billion gallons by 1997. As
a result, annual methanol demand would grow by 800 million
gallons and annual natural gas demand would grow by 62.3 billion
cubic feet over this time frame.

     The reduced growth in demand for MTBE, methanol, and natural
gas will tend to reduce the growth in employment and investment
in these industries relative to what would have occurred in the
absence of the renewable oxygenate program. However, additional
jobs would tend to be created in the production and distribution
of renewable oxygenates and their feedstocks. EPA has not
received sufficiently comprehensive, reliable, and accurate data
to permit determination of the net employment effects of the
renewables requirement but believes that the RFG program will
lead to significant job growth in the natural gas, methanol, and
MTBE industries relative to their current levels with or without
the renewables program.

E.   Impact on Tax Revenues and the Highway Trust Fund

        Many commenters noted that any increase in ethanol use
resulting from the renewable oxygenate program would reduce
revenues generated for the Highway Trust Fund. The reduction in
revenues would occur because ethanol blended into motor fuel is
granted an exemption of 54 cents per gallon of ethanol from the
highway excise tax. Based on EPA's estimate that approximately
335 million additional gallons of ethanol will be blended into
gasoline each year as a result of the renewables program, this
tax exemption would cost the Highway Trust Fund approximately
$181 million annually. An additional $0.06 per gallon of ethanol
(or $20.1 million annually) is diverted from the Highway Trust
Fund to the General Fund if ethanol is blended at 10 volume
percent, so the total loss of Highway Trust Fund revenues could
be as much as $201 million annually. It should be noted that
this cost would tend to shrink if ETBE use expands beyond the
level at which refineries can maintain segregated distribution
and take advantage of the current excise tax exemption.

        The available information on new ethanol facilities under
construction also suggests that approximately 176 million gallons
of annual capacity would be eligible for the small ethanol
producer credit of $0.10 per gallon. The total impact of this
credit on the General Fund could be as much as $17.6 million in
reduced tax revenues annually, assuming that all eligible
facilities operate at full capacity. Hence the net loss of
federal tax revenues due to the renewables program could be as
large as $199 million annually.

        In addition, a number of states have granted ethanol-blended
gasoline substantial tax credits or exemptions from state-level
fuel taxes. The degree to which the renewables program would
affect state revenues is difficult to forecast for several
reasons, however. First, some states only grant tax credits to
ethanol blended at certain levels, typically 10 volume percent
(equivalent to 3.5 weight percent oxygen). EPA has no way to
forecast with any accuracy the change in volume of gasoline that
would qualify for the relevant tax exemptions in various states.
Second, the renewables requirement must be met on a nationwide
basis, which makes it difficult to forecast the change in ethanol
use on a state-by-state basis.

        EPA received comments from at least one state expressing
concern over the potential loss in highway construction funds
available to the state resulting from increased ethanol use under
the renewables program. EPA also received several comments
claiming that the reduction in highway trust fund revenues would

reduce the number of highway construction jobs. EPA acknowledges
that such an outcome is possible but does not have sufficient
information to quantify this effect at the present time. In
particular, EPA does not have sufficient information to determine
the extent to which alternative funding sources would offset any
reduction in highway trust fund revenues. Furthermore, any
adverse impacts resulting from reduced highway trust fund
revenues are likely to shrink as ETBE use increases, particularly
in 2000 and beyond when the Phase II RFG requirements create
strong incentives for ETBE use independent of the renewable
oxygenate program.

F.   Impact on Farm Support Payments

     To the extent that the renewables program increases crop
prices and farm incomes, Federal outlays for deficiency payments
may be reduced. While the increased farm income from crop price
increases represents a transfer of income from one sector to
another, reductions in deficiency payments represent a real
savings to the economy. As discussed in section IV.C, the
renewables program is projected to reduce farm deficiency
payments by $220-$369 million annually.[56] In other words, USDA
estimates that each gallon of ethanol production reduces farm
deficiency payments by $0.66 to $1.10.

     USDA also submitted comments suggesting that the renewables
program will reduce deficiency payments by approximately $253
million annually (based on a $454 million savings for a 600
million gallon increase in ethanol production). In addition,
USDA referenced a General Accounting Office study that estimated
the net effects on Federal revenues and outlays resulting from
changes in deficiency payments and highway trust fund revenues.
Again assuming that these payments and revenues vary linearly
with ethanol demand, USDA's comments indicate that the net effect
of the reduction in deficiency payments and highway trust fund
revenues would be a net gain to the Treasury of approximately
$163 million annually due to the 335 million gallon increase in
ethanol use projected to occur as a result of the renewables
program. Given EPA's estimate of highway trust fund revenue
losses presented in section IV.E, the GAO estimate implies a
reduction in farm deficiency payments of approximately $344

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     [56] John W. McClelland of USDA, "Memorandum for Richard
Wilson, Director, Office of Mobile Sources, U.S. Environmental
Protection Agency," June 20, 1994.

million annually. These values fall within the range presented above.

It should be noted that all of these estimates depend strongly on the projected increase in crop prices resulting from this rule. EPA received many comments from agricultural groups arguing that the renewables rule would have little impact on overall corn production, which would suggest that the renewables rule might have little impact on crop prices. Furthermore, commercialization of renewable oxygenate production processes which use farm wastes or other cellulosic feedstocks might reduce corn demand and prices, though some of the lost income could be offset by income from energy crops or farm wastes. The relative magnitude of these price and income changes depends on the price elasticity of demand for corn and other ethanol feedstocks and cannot be estimated accurately by EPA at this time.

Several commenters noted that historically only a small fraction (approximately 30%) of the price paid for ethanol is received by farmers. However, the renewable oxygenate program is not being promulgated to increase farm income; rather, increased farm income represents a beneficial side effect to the renewable oxygenate program but is not the reason why EPA is promulgating the renewable oxygenate program.

G.   Other Comments

1.   Balance of Trade

In the December proposal, EPA suggested that the renewable oxygenate program could help reduce imports of crude oil and fossil-fuel-based oxygenates. EPA received numerous comments regarding the trade benefits and disadvantages of the renewable oxygenate program. Based on those comments and on a more detailed analysis of the impact of the renewables program, EPA is no longer claiming significant trade-related benefits from the renewables program. Furthermore, EPA is no longer projecting that the renewables program will reduce overall crude oil use, though EPA does project an overall reduction in fossil energy use due to the renewables program. The impact of this or any other program on imports and exports is complex and difficult to determine. For example, reducing imports of crude oil or MTBE might reduce other countries' ability to purchase goods and services from the U.S., with uncertain effects on employment and gross domestic product. Furthermore, reductions in MTBE demand might disproportionately affect domestic MTBE producers rather than foreign producers, particularly if domestic producers have

higher operating costs than foreign producers. Finally, the
Uruguay Round of negotiations on the General Agreement on Tariffs
and Trade may lower trade barriers dramatically, including
barriers to ethanol produced overseas. As a result, EPA is no
longer claiming that the renewable oxygenate program necessarily
will reduce crude oil use, crude oil imports, ether imports, or
the nation's balance of payments deficit.

2.   Crude Oil Usage and Imports

     EPA received a number of comments which noted that the
renewables program is likely to increase crude oil imports, at
least in the near term, as smaller volumes of ethanol are
substituted for larger volumes of MTBE. EPA acknowledges that
crude oil imports might increase in the short term relative to
what would have occurred under the RFG final rule in the absence
of the renewables program, but notes that to the extent the
renewables program increases the use of ETBE made from ethanol
and natural gas-derived isobutylenes, the renewables program will
reduce crude oil use since more ETBE than MTBE is needed to
satisfy the RFG oxygen requirement. In any case, the overall RFG
program will reduce crude oil imports, even with the renewables
requirement. These points are discussed more fully in section
II.

     EPA also received comments noting that the cost of the
program per barrel of crude oil saved was as high as $118 to $287
per barrel. However, the renewables rule is not being undertaken
to reduce crude oil use. Rather, it is being undertaken to
achieve the fossil energy and long-term global warming benefits
discussed in the preamble to the final rule and to mitigate the
effects that the RFG rule might otherwise have on the renewable
fuels industry (thereby helping to make the RFG rule consistent
with long-running Congressional and Administration policy).

3.   Fuel Subsidies

     EPA received numerous comments alleging that crude oil and
natural gas producers receive direct or indirect subsidies as
large or larger than the tax subsidy provided to ethanol
blenders. It was argued that military expenditures related to
the Persian Gulf War, preferential tax treatment for oil
exploration, and a variety of environmental externalities amount
to *de facto* subsidies for crude oil production and use. EPA has
not attempted to determine the scope of all direct and indirect
subsidies provided to crude oil or to ethanol, in part because
accurate and reliable information is not available to do so and
in part because an appropriate methodology to allocate such costs

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is not available and because such allocations are extremely difficult to make from a technical perspective.

4.   Competitive Effects

EPA received several comments suggesting that the renewable oxygenate program would increase competition in the oxygenate market and thereby reduce oxygenate prices. EPA acknowledges that by assuring a place for renewable oxygenates, the renewables program assures that a diverse supply of oxygenates is available. However, EPA is not prepared to claim that the renewables program will reduce oxygenate prices. While MTBE prices may decrease as demand for MTBE is reduced, and while these reductions may outweigh any increase in ethanol prices or related costs, insufficient information is available to quantify these effects with adequate certainty. In addition, EPA does not have sufficient data to justify the commenters' claims given the large body of economic theory and empirical research which suggests that market share mandates tend to increase prices.

Other commenters argued that competition would be stifled because of the dominance of the existing ethanol industry by a single company, Archer Daniels Midland. Current market share, however, is only one element of market power. Barriers to entry are also a key determinant of market power. Based on the large number of companies involved in ethanol plant projects, including planned and under-construction plants, it appears that barriers to entry are not so large as to forestall competition among ethanol producers, regardless of current market share positions.

5.   Regional Effects

EPA received several comments which noted that the renewables program would benefit one part of the country (the Midwest, where ethanol and its feedstocks are produced) at the expense of other parts of the country (the regions which participate in the RFG program, notably the Northeast). EPA also received comments from a number of State agencies attempting to quantify the impact of current or projected ethanol demand on the farm economies in their states. EPA acknowledges that some inter-regional transfers are likely under the renewables program, but the amounts involved are likely to be small relative to the overall impact of the RFG program. EPA believes that the cost analysis presented above is a reasonable assessment of the program's overall impact on the nation's economy.

6.   Impact on Small Refiners

EPA received several comments which claimed that the renewable oxygenate program would have a disproportionate impact on smaller refiners. However, the averaging and trading provisions of the program are designed to give refiners, particularly small refiners, the ability to meet the requirements of the program without having to bear high capital or operating costs. In addition, the phase-in of the renewables requirement is designed to allow the requirement to be met by blending ethanol into non-VOC-controlled gasoline, thereby avoiding the need for refiners to produce lower-RVP blendstocks for ethanol blending. Hence EPA has concluded that the renewables program will not impose a disproportionate burden on smaller refiners.

V.   Seasonal Issues and Alternatives

A.   <u>Shoulder Season</u>

1.   Background and Major Comments

EPA is requiring that oxygenates derived from renewable sources be used to fulfill thirty percent of the oxygenate requirement for reformulated gasoline (RFG), year round. EPA expects the renewables requirement to be met primarily with ethanol, at least in the near term. ETBE may be used, albeit not much in the early years of the program (due to capacity limitations); starting in the year 2000 more ETBE use is anticipated since it will enable refiners to more easily meet the stricter Phase II RFG standards. However, renewable oxygenates which cause volatility-related commingling effects (such as ethanol) when mixed with other oxygenate blends can only be credited toward the renewables requirement when used in gasoline that is not subject to VOC control. Although ethanol can still be used in reformulated gasoline in the VOC control season ("summer"), the renewables requirement does not provide additional incentive to do so.

State regulators and their representatives, such as STAPPA/ALAPCO, NESCAUM, and CARB, among others, have expressed concern that increased ethanol use would occur during the shoulder season[57] as a result of the renewable oxygenate program. The vapor pressure boost, commingling, and distillation effects which would occur with this increased ethanol use would be problematic for states in achieving the NAAQS for ozone. As explained in section III, with greater ethanol use, the commingling and distillation effects (as well as the vapor pressure boost in gasoline not subject to VOC control) would potentially create detrimental environmental impacts. The net result of such increases in average volatility levels during the shoulder season would be increased VOC emissions and potentially higher ozone levels, especially in the Northeast and California. NESCAUM suggested that EPA extend the season in which volatility-increasing alcohols would not receive renewable credit to April 1 through October 31 in order to eliminate the risk of any potential ozone increases for the Northeast.

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[57] The "shoulder season" (generally April 1 through April 30 and September 16 through October 31) refers to the months bordering the RFG VOC control season (May 1 -September 30).

EPA acknowledges that the renewables program may have the potential to affect the rate of ozone formation in the shoulder season by affecting the level of VOC emissions resulting from the use of reformulated gasoline during those months. Although EPA's Simple and Complex Models assume non-exhaust VOC emissions to be zero outside the high ozone season, EPA recognizes that this assumption is unlikely to be true in all areas on all days outside the high ozone season. As discussed above in section III, ethanol blends can increase emissions of non-exhaust VOC due to three effects: the "RVP boost" which occurs upon blending ethanol into gasoline, the commingling effect, and front-end distillation effects. The Simple Model indicates that an RVP increase of 1.0 psi upon blending ethanol into RFG would result in an increase of over 25% in VOC emissions during the VOC control season (all other fuel parameters remaining constant), but gives no indication of what would occur during the rest of the year. Furthermore, an analysis contained in the Regulatory Impact Analysis (RIA) for the final rule for the reformulated gasoline program shows that the commingling and distillation effects associated with ethanol blends could increase total VOC emissions by 5 percent (relative to MTBE blends) if ethanol blends comprise 30 percent of the market. Although insufficient data is available for EPA to quantify the impact of the RVP boost, commingling, or distillation effects on emissions from non-VOC-controlled RFG, EPA anticipates that these effects would increase VOC emissions. The following sections present EPA's analysis of this issue.

2.   Current Air Quality Pattern in the Shoulder Season

In examining the shoulder season issue, EPA evaluated the extent of the air quality problem by looking at the number of exceedances which violated the national ozone standard. EPA evaluated the annual exceedances, the winter and summer exceedances separately, as well as those which occurred during the months of April, October and the latter half of September. EPA found that ozone exceedances outside the May 1 to September 15 period (when only VOC-controlled RFG may be in the distribution system) rarely occur for those RFG areas outside of California and Texas. Ozone exceedances, as obtained from environmental site monitors in the Northeast, during the shoulder months comprised fewer than 4 percent of all such exceedances recorded in RFG areas in 1986-1988. More recent 1990-1992[58] data

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[58]   The ozone air quality site monitoring data for 1990 - 1992. The U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Technical Support Division,

for the Northeast confirm the earlier results: less than 1 percent of all ozone monitor exceedances recorded in RFG areas occurred in the Northeast in April or late September/October. Further examination of the 1990-1992 data revealed that the documented ozone violations involve just two distinct ozone episodes, as is demonstrated by Table V-1:

TABLE V-1: 1990-1992 OZONE EXCEEDANCES DURING THE SHOULDER SEASON IN REFORMULATED GASOLINE AREAS (Excluding California and Texas)

Month	Exceedances	(%)	State	Date
April	3	(0.05%)	New Jersey	4/27/90
			Pennsylvania	4/27/90
			Rhode Island	4/27/90
Sept. 16-30	5	(0.08%)	Connecticut (2)	9/17/91
			Maryland	9/16/91
			New Jersey	9/16/91
			Virginia	9/16/91
October	0	(0%)	None	--

Since the ozone exceedances occurring in both April 1990 and September 1991 are on the same day (except Connecticut) and in states near each other, it is safe to assume that the exceedances were actually one episode for each month. Therefore, just two shoulder season exceedances occurred in 1990 - 1992. These episodes happened very near the time when VOC-controlled RFG will be required at the terminal level (May 1 through September 15).

While the 1990-1992 data does not demonstrate a significant air quality problem in the Northeast during the shoulder season, it does indicate that a substantial number of ozone exceedances occurred during the shoulder season in the reformulated gasoline areas of California and Texas. Documented exceedances have occurred throughout the year in both states, as depicted in Table V-2.

National Air Data Branch. March 24, 1994.

TABLE V-2: ANNUAL OZONE EXCEEDANCES IN CALIFORNIA AND TEXAS FOR THE YEARS 1990-1992

(Expressed as Percent of Total Exceedances)

	May	Summer[1]	Shoulder[2]	Winter[3]	Annual
California	273 (5%)	2794 (50%)	1206 (22%)	94 (1.7%)	4367 (79%)
Texas	34 (0.6%)	199 (3.6%)	117 (2%)	17 (0.3%)	367 (6.7%)
All Other RFG Areas	62 (1.1%)	706 (13%)	8 (.2%)	0 (0%)	776 (14%)
Total U.S.					5510

[1] The summer season is consistent with the high ozone, VOC-control period for reformulated gasoline (June 1 - September 15).

[2] The shoulder season includes the months of April and October, as well as September 16 - 30.

[3] For purposes of the shoulder season ozone analysis, the winter season includes November, December, January, February and March.

3.   Program's Impact on the Shoulder Season

EPA does expect increased ethanol use in non-VOC-controlled gasoline is likely. However, the Agency's analysis indicates that any detrimental environmental effects should be negligible. Since the high ozone season is June 1 - September 15, all fuel at the service stations must comply with the VOC control standard during that period. In order to ensure that reformulated fuel is at the service stations on June 1, the RFG regulations require VOC-controlled fuel at the terminal beginning May 1. Thus, all fuel at the terminals must comply with reformulated gasoline requirements from May 1 through September 15. Refiners must produce VOC-controlled RFG prior to May 1 to allow for timely terminal compliance. In fact, some refiners have indicated in comments submitted to EPA that they would begin shipping such fuel as early as March 1 in order to assure that low-volume terminals and retail stations have converted to VOC-controlled RFG by May 1 and June 1, respectively, as required by the RFG program.

An EPA analysis of fuel turnover[59] indicates that since most fuel is sold at high-turnover retail outlets, most vehicles will begin operating on VOC-controlled RFG during April. While increased ethanol use is likely in RFG sold from mid-October through late March, increased ethanol use resulting from this program will be essentially zero in May and will be minimal in April, late September, and early October as supported by the information presented above. Hence, VOC emission impacts resulting from increased ethanol use will be minimal as well. And since ETBE use in summer RFG would likely reduce ethanol use in winter RFG as well, the extent of any ethanol-related VOC increase during the shoulder season is likely to decrease as ETBE capacity and usage increase. Also, most vehicles will continue to operate on VOC-controlled RFG until late September or early October, since the fuel distribution system requires some time to replace summer fuel with winter fuel after refiners are permitted to switch production on September 16. Experience with the federal volatility program demonstrates that the fuel distribution system requires some time to turnover to summer fuel: it takes approximately 25 days on average for the fuel distribution system to become totally free of a specific fuel[60]. In fact, the recently promulgated RFG regulations[61] reflect that assumption. Thus due to fuel turnover and fuel distribution system replacement lag-time, summer reformulated gasoline is likely to be available at many, if not most, retail outlets during April and to remain available until late September or early October, especially the high volume retail outlets. Consequently, little additional use of ethanol may result during the shoulder season as a result of the renewable oxygenate program.

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[59] Memorandum from Rick Rykowski, Assistant to the Director, to Chester J. France, Director, Regulation Development and Support Division. "Impact of Renewable Oxygenate Program on Dispensed Gasoline RVP Before and After the Summer VOC Control Season." June 17, 1994.

[60] The regulations for reformulated gasoline presume a 25 day turnover period for the purpose of assigning penalties (see §80.80(d)(2)), as discussed in the Response to Comments Document for the RFG final rule (Public Docket A-92-12, Item #V-C-1).

[61] 59 FR 7715, February 16, 1994. §80.80(d)(2) of the Reformulated Gasoline final regulations which discusses the length of time the gasoline in question remained in the gasoline distribution system for purposes of determining compliance penalties.

Even if ethanol use did increase during the shoulder season, it should be noted that as ethanol-blended fuel increases in market share from 30 percent to as high as 70 percent, the commingling effect remains essentially unchanged; at higher levels of ethanol use, the commingling effect would diminish. See Section III.A.-Figure III-2 for a depiction of the commingling curve. As discussed in the preamble, many areas already expect to have winter ethanol levels at or near 30 percent under the RFG program. Consequently, EPA considers it unlikely that a significant increase of commingling-related RVP levels and VOC emissions will occur as a result of implementation of the renewables requirement.

Additionally, EPA believes that other emission control programs will help alleviate any ozone air quality problems which may result from implementation of the renewable oxygenate program. For example, although the federal gasoline volatility control program, reformulated gasoline program, and renewable oxygenate program have all been tailored to focus ozone related emission reductions during the summer only, the vast majority of emission control programs apply year-round. Some examples of national programs include the Inspection and Maintenance program, onboard vapor recovery, and Tier 1 tailpipe standards. Each of the aforementioned air quality initiatives are designed to reduce ozone-related emissions. Thus, the combined spill-over and alternate emission reduction program effect should reduce such precursors during the shoulder season by more than any increases due to increased ethanol use, thereby negating any detrimental environmental impact.

As mentioned in Section V.A.1, NESCAUM suggested excluding oxygenates which increase volatility through commingling from participation in the renewable oxygenate season from April 1 through October 30. The reason for their concern was that states are relying on the environmental benefits of the reformulated gasoline program in order to meet the emission reduction requirements of their State Implementation Plans (SIPs). EPA understands that, from a state perspective, any federal requirement which may impinge on the expected environmental benefits of RFG is cause for alarm. However, the environmental implications of the renewable oxygenate program in the shoulder season (from increased use of ethanol) will not reduce the VOC benefits of the RFG program during those months when states must demonstrate emission reductions in their SIPs. Furthermore, as this analysis has shown, the potential for the renewable oxygenate requirement to result in ozone violations outside of the high ozone season is very small in most states.

For both California and Texas, however, there is a possibility that the renewable oxygenate program may increase the risk of ozone exceedances outside the high ozone season, based upon prior history. However, the state of California has exercised its authority to impose additional fuel regulations within its borders, and established more stringent volatility requirements that go into effect throughout the state April 15, 1996.

Texas is in a different situation. Although Texas did not submit comments to the Agency on this issue, EPA's analysis has shown that increased VOC emissions outside the high ozone season, should they occur, increase the risk of ozone exceedances in the Houston and Dallas-Fort Worth RFG areas. Most non-summer ozone exceedances in Texas occur in Houston, which has a very high VOC to NOx ratio in the ambient air. In general when this is the case, ozone levels are believed to be more strongly driven by NOx emissions than by VOC emissions.[62] Any ethanol-related increase in VOC emissions would, thus, be expected to have relatively small effects on ozone. Recent modelling, however, while not conclusive, suggests that VOC emissions may also be very important in Houston. Given this uncertainty, it is difficult for EPA to draw a conclusion about the likely impacts on ozone in Texas of the renewable oxygenate requirement.

Nevertheless, in recognition that states may wish to address their unique air quality problems, EPA has decided to allow States to petition the Administrator to extend the season during which ethanol blended into gasoline would not receive credit toward the renewables requirement. The provisions governing the petition process are described in detail in Section III.B.4. of the preamble. To the extent there may be a state-specific problem from VOC emissions related to increased ethanol use outside the high ozone season, this process provides an efficient and flexible procedure to resolve such problems.

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[62] National Academy of Science, *Rethinking the Ozone Problem in Urban and Regional Air Pollution*, 1992.

4.   Other Comments

    The Agency also received a number of comments which
supported the view that the renewable oxygenate program would not
increase ozone violations during the shoulder season. The Clean
Fuel Development Coalition argued that since the renewable
percentage of the program being promulgated is small and since
brand loyalty reduces the commingling effect of fuels, the
renewables requirement is unlikely to have a significant impact
on ozone air quality. Other commenters provided additional
reasons which support the claim that the use of ethanol-blended
RFGs during the shoulder season would not cause additional ozone
exceedances for several reasons. For example, the sale and
distribution of VOC-controlled RFG, primarily ether-containing
RFG, outside of the VOC-control season would reduce shoulder
season RVP levels below current levels. In addition, other
pollution reduction programs being implemented over the next
several years would reduce ozone precursor emissions during the
shoulder season. Finally, some commenters felt that VOC emission
increases during the shoulder season resulting from the use of
ethanol would be mitigated with the use of higher blends of
ethanol.

    The Agency agrees with most of these comments, and believes
that they provide further support for the analysis presented
above. EPA does not agree with CFDC's assertion that brand
loyalty will reduce the commingling effect of fuels, as the
Agency's commingling analysis (presented in the RIA for the final
RFG rule) already takes the effects of brand loyalty into
consideration.

B.   Split Season

1.   Background and Comments

    EPA's proposal would permit year-round averaging and credit
trading in order to increase flexibility to refiners. EPA's
position was that an annual averaging program combined with
credit trading would allow refiners to fulfill the requirements
of the ROXY program in the manner which is most cost-effective
for their specific refinery. To the extent that supply shortages
could occur in the early years of the program in some markets,
the averaging and trading provisions would minimize the
likelihood of extreme price increases or RFG shortfalls in these
areas.

USDA suggested in its comments that EPA adopt a season-specific averaging program, rather than an annual averaging program. The American Corn Growers and the Clean Fuel Development Coalition also encouraged the Agency in their comments to promote ETBE use by promulgating a summer ETBE mandate (ACG) or a seasonal averaging program (CFDC). A seasonal program would require the 30 percent renewables provision to be met separately for both summer (VOC-controlled) and winter (non-VOC-controlled) reformulated gasoline, with no trading of credits between seasons.[63]

USDA argued that a season-specific program would increase the environmental benefits of the program. Specifically, USDA stated that the reduction in summer ethanol use resulting from a "split season" would lead to VOC emission reductions over what would occur absent such a program. According to USDA's analysis, seasonal averaging (since it would promote the use of renewable ethers during the VOC-control season) would reduce VOC emissions by 3 to 6 percent (5 - 19 thousand tons of VOC reductions annually) when compared to emissions that are likely to occur with annual averaging. These VOC emissions benefits would result from reductions in non-exhaust VOC emissions when ethers (specifically ETBE) displace alcohols (ethanol) in the summer months, since ethers do not exhibit the commingling and front-end distillation effects expected with alcohol use.[64]

2.   Supply Impacts

As discussed in Section I, ethanol supply and distribution limitations may exist, particularly in the short run; these problems would be increased for ETBE production. Seasonal averaging would require ETBE use in VOC-controlled reformulated gasoline, which presents serious capacity problems in the short-term. EPA's analysis indicates that insufficient ETBE capacity would be available to meet the summer requirements of a season-specific renewables program for several years. A fraction of current MTBE capacity is capable of producing ETBE with minor modifications. However, due to the restrictions of the chemical

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[63]   USDA also suggested that, since their analysis showed that there were greater environmental benefits to be obtained during the summer season of a split season program, trading could be allowed from the summer VOC-controlled season to the winter non-VOC-controlled season, but not vice versa.

[64]   See section III above for additional discussion of these impacts.

reactions involved in ether production, the volume of ETBE produced at such facilities will be significantly less than the volume of MTBE produced. Hence, it is likely that most ether producers will require the addition of capital equipment to produce sufficient quantities of ETBE. It would likely take several years until adequate capacity was added to make sufficient quantities of ETBE to meet the needs of a split season. As a result, in the early stages of the program little ETBE is likely to be available. Consequently, a split season would have to be delayed and/or phased in, probably until the latter part of Phase I of the RFG program. This position was supported by many of the comments received.

3.   Cost and Program Complexity Impacts

A split season program would introduce additional complexity and expense to the renewable oxygenate and reformulated gasoline programs. ETBE is more expensive on an oxygen content basis than either MTBE or ethanol. Furthermore, ETBE provides smaller toxics emission reductions than other oxygenates included in EPA's RFG emission models, as depicted in Table V-3. The figures from the table were derived by using EPA's reformulated gasoline certification models. In the applicable model, the oxygenate ETBE was substituted for MTBE. The models subsequently predicted the increase in toxics emissions for each of the three scenarios, as depicted in the first row of Table V-3. Rows 2 and 3 of the table depict the changes a refiner would need to make in a reformulated fuel's aromatics and benzene parameters to meet the RFG toxics compliance requirements.

TABLE V-3: Toxics Compliance Of RFG with ETBE

Change in	Simple Model	Summer Complex Model	Winter Complex Model
Toxics Emissions	+2.3 %	+4.45 %	+4.68 %
Required Aromatics	-2.1 vol%	-7.9 vol%	-6.1 vol%
Required Benzene	-0.2 vol%	-0.25 vol%	-0.43 vol%

As discussed in section IV, the use of ETBE in the summer and ethanol in the winter (as would occur under a split season program) increases the costs of complying with the toxics requirements of both Phase I and Phase II RFG, when compared to a scenario in which all of the ROXY requirements are met with ethanol use in the winter (and MTBE is the oxygenate of choice for RFG in the summer months). Furthermore, the need to reduce

toxics emissions further limits the flexibility of refiners in meeting all of the performance standards for RFG, since not all refiners have the capability to easily adjust aromatics content while maintaining octane. In addition, unless the requirements for a separate renewable oxygenate requirement for the VOC-control season were phased-in, with a delayed implementation date, refiners would have little leadtime before the start of the RFG program to make the necessary process adjustments to meet the toxics standards, even if they could obtain sufficient quantities of ETBE in the near term.

A split season introduces additional complexity to the renewable oxygenate program since it restricts averaging and trading and thus may reduce compliance flexibility and increase costs. By forcing all refiners to use ETBE in the summer, a split season program loses the benefit of permitting those for whom it is more convenient or economical to use ETBE to do so, and those for whom it is more convenient or economical to use ethanol, to do so, any time throughout the year. Furthermore, a seasonal averaging period limits averaging and trading privileges to a specific season, and refiners would not be permitted to demonstrate that they have met the requirements over the course of the entire year. Refiners thus would be forced to demonstrate that they have met the applicable 15 or 30 percent renewable oxygenate requirement in a much shorter time period. This lack of flexibility would be especially problematic during the first years of the program when ETBE availability would be limited. In addition, unless it was phased-in with a delayed implementation date, a seasonal averaging and trading provisions would not provide refiners with additional time to meet the initial requirements of the program, and would not allow them to smoothly ramp up their use of renewable oxygenates during the course of the first year to the full 30% requirement for 1996.

Finally, a split season may have very little impact in spite of the analysis presented by USDA. As shown above, a split season would have to be phased in with a delayed implementation date to avoid serious disruptions to the market, particularly in the summer VOC-controlled season. Hence, a renewable oxygenate program comprised of a split season would not be fully effective until the late 1990s (unlike an annual program that would be phased in starting in 1995 and fully effective in 1996). Furthermore, the RIA for the reformulated gasoline final rule shows that the Phase II RFG standards are likely to stimulate ETBE use in 2000, due to the more stringent requirements and the inherent benefits of ETBE in meeting those requirements. To the extent that this course of events occurs, it would not be

necessary to force a split season, because the end result would
be similar.

4.   Energy Impacts

The DOE study of the fossil energy implications of the
renewable oxygenate program (discussed in section II above)
indicates that the use of ETBE in the summer will not provide
greater fossil energy benefits than the use of ethanol in the
winter, regardless of whether existing or new ethanol capacity is
used. With the use of ETBE during the summer months, the program
may achieve some marginal crude oil savings due to the favorable
front-end distillation characteristics of ETBE relative to
ethanol and MTBE. However, overall it appears that a split
season program would have at most marginal benefits compared to
an annual program. The negative impacts of a split season
outweigh these small potential benefits.

5.   Environmental Impacts

As mentioned previously, the use of ETBE in the summer may
provide some reduction in VOC emissions since the commingling and
front-end distillation effects of ethanol use would be reduced
(by displacing summer ethanol use to meet the ether production
levels required under a split season program).[65] However, as
demonstrated above, this would occur to some extent by the year
2000 anyway, when the Phase II RFG standards will serve to
encourage the use of ETBE, regardless of the existence of a split
season.

There may be small benefits of a split season in terms of
the global warming implications of the ROXY program. The DOE
study indicates that the use of ETBE in the summer to meet part
of the ROXY requirements may result in marginally lower emissions
of carbon dioxide than the use of ethanol only in the winter.
However, once again the magnitude of and uncertainty in these
numbers does not make these benefits worth the supply disruptions

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[65]   ETBE has some front-end distillation benefits over MTBE,
as well. Hence, under a split season program there would be
small additional benefits from requiring the use of non-
commingling renewable oxygenates in the summer months, but only
to the extent that ETBE was used as opposed to renewable MTBE.
Under an annual program, ETBE will result in benefits to the
extent that it is used in the summer months (and displaces MTBE
use).

and increased costs that would occur under a split season requirement.