Control of Hazardous Air Pollutants from Mobile Sources

Summary and Analysis of Comments

Chapter 4
Gasoline Benzene Control Program

Assessment and Standards Division
Office of Transportation and Air Quality
U.S. Environmental Protection Agency

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SUMMARY AND ANALYSIS OF COMMENTS:
CHAPTER 4
GASOLINE BENZENE CONTROL PROGRAM

4. GASOLINE BENZENE CONTROL PROGRAM

What We Proposed:

The comments in this chapter correspond to Section VII of the NPRM and relate to our proposed gasoline benzene control program. A summary of the comments received, as well as our response to those comments, are presented for each issue. For the full text of comments summarized here, please refer to the public record for this rulemaking.

4.1 Standards

4.1.1 Benzene Standards

4.1.1.1 Average Standard of 0.62 Vol% Is Not Stringent Enough

What Commenters Said:

Many commenters supported a more stringent average benzene standard than the proposed standard of 0.62 vol%. Most of these commenters supported an average standard of 0.52 vol%; one commenter suggested a standard between 0.62 vol% (the current average benzene level for RFG) and 0.41 vol% (the lowest individual refinery level in 2003). These commenters gave two main reasons for a more stringent standard: 1) that a more stringent standard is feasible, and 2) a more stringent standard could be achieved at a reasonable cost.

Comments supporting the feasibility of a more stringent standard pointed out that a number of refineries are producing gasoline today with benzene content well below the proposed average standard. Several commenters argued that the average standard should be sufficiently stringent that all refineries, especially those with higher benzene levels, would be required to use similar technologies and achieve similarly low levels. Some of these commenters point to EPA's analysis showing that a standard as low as 0.52 vol% would be feasible from a strictly technological standpoint. One commenter, the New York Department of Environmental Conservation, stated its belief that because gasoline in the New York metropolitan area is already low compared to other parts of the country, the proposed average standard would not likely result in further reductions in that area.

Regarding cost, several commenters observed that EPA's analysis showed that while a much more stringent standard of 0.52 vol% would increase average costs by more than a factor of two, the resulting average costs per gallon would still be less than were projected for the gasoline sulfur program, which EPA considered reasonable in that instance.

Our Response:

While many of the comments on the level of the average standard discuss technological feasibility and cost separately, we believe that the statute requires us to consider these factors together (see Sierra Club v. EPA, 325 F. 3d at 378**)**.[1] In the proposal, we considered a range of levels for the average benzene standard, taking into account technological feasibility as well as cost and the other enumerated statutory factors. We have reassessed the level of the standard in light of these factors, and have concluded that the proposed level of 0.62 vol% is the appropriate level for the average standard, because it achieves the greatest achievable emission reductions through the application of technology that will be available, considering cost, energy, safety, and lead time.

In the proposal, EPA described in detail what we believe would be the consequences to the overall goals of the program of average standards of different stringencies (see 71 FR 15866-67). These anticipated consequences relate in large part to how we believe refiners would respond to the benzene averaging and benzene credit trading provisions that were integral to the proposed program. For the final rule, we have reassessed how we believe refiners would respond to different average standards. We continue to believe that increasing the stringency of the average benzene standard could have the effect of reducing the number of benzene credits generated, since fewer refineries are likely to take actions to reduce benzene further than required by the standard. At the same time, a more stringent standard would increase the need for more technologically challenged refineries to purchase credits. Directionally, we showed at proposal that a more stringent average standard would increase costs for these refineries. This is because credits may be less available and/or less affordable as an alternative to immediate capital investment, and investment in relatively expensive benzene saturation equipment would be necessary for a greater number of refiners that could not comply with credits alone. For the final rule, we specifically considered a level of 0.50 vol% for the average standard, which we expect would require all refineries to install the most expensive benzene control technologies (either benzene saturation or benzene extraction). We concluded that this level would clearly not be feasible, considering cost. In a related analysis, we also showed that if, contrary to our expectations, credits were not easily available as a compliance option, there are several refineries for which it may be technologically feasible to reach benzene levels below 0.62 vol%, but only at costs far greater than for most other refineries.[2]

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[1] "[P]etitioners point out that section 202 (l) (2) is 'technology-forcing,' so that the agency must consider future advances in pollution control capability. This is not disputed, but doesn't take petitioners far. The statute also intends the agency to consider many factors other than pure technological capability, such as costs, lead time, safety, noise and energy. And its language does not resolve how the Administrator should weigh all these factors in the process of finding the 'greatest emission reduction achievable.'"

[2] It is true that the final rule contains a hardship provision which could apply to individual refineries facing extreme economic or other hardship in meeting the benzene standards. However, the existence of this provision does not mean that EPA can reasonably adopt more stringent standards assuming that refineries may obtain some type of hardship waiver. The hardship provision is designed to accommodate those rare situations where, contrary to predictions now, a refiner faces unusual circumstances resulting in extreme hardship affecting its ability to comply. If grant of hardship relief from the benzene standards became a norm rather than an exception, EPA doubts that the standard would reflect "maximum emissions reductions achievable" since demonstrably the standard would not be being achieved by many refineries.

The commenters supporting a more stringent average benzene standard did not provide data or analysis to address the potential negative effects of different standards that we presented in the proposal, especially in the context of the proposed ABT program. Many comments that supported a more stringent standard pointed to average costs projected in the proposal that are higher than for the proposed standard, but are not large on a per-gallon basis compared to other EPA fuel programs. However, even assuming that it is relevant here to consider per-gallon costs for removal of sulfur in other rulemakings,[3] these commenters did not address the wide range of compliance costs for individual refineries that we discuss in the proposal (see Chapter 9 of the RIA). It is critical to recognize that as more stringent average standards are considered, the costs for individual technologically-challenged refineries tend to become very high. This potential for high costs at more stringent average standards exists if, as we expect, the ABT program functions as it is designed to; if the ABT program functions less efficiently than projected, the costs for some individual refineries could be higher still.

As noted above, we believe that there are increasingly significant issues of cost and technological feasibility for a variety of refineries as average standards below 0.62 vol% are considered. We remain convinced that an average standard of 0.50 vol% would clearly not be a feasible nationwide program, considering cost, since so many more refineries would need to use the highest-cost benzene control technologies. As at proposal, EPA continues to believe that setting an average standard more stringent than 0.62 vol% would necessarily begin to create the serious issues we identified for a standard of 0.50 vol%. Yet, as our updated analyses continue to show, these concerns do not appear to be significant at a level of 0.62 vol%. We therefore continue to believe that an average standard of 0.62 vol%, in the context of the ABT program, will maximize the benzene reduction nationwide, will minimize the likelihood of refineries experiencing extreme costs, and will reasonably distribute costs nationwide among refineries.

The NY DEC is correct in highlighting that some areas of the country already have such low benzene levels that the opportunity or further control is more limited. However, although current benzene levels in some areas are indeed lower than 0.62 vol%, this does not mean that all refiners and importers in those areas have fully implemented all of their benzene control potential. We believe based on our refinery modeling that the ABT program will create incentives for refiners in all areas to consider further benzene reductions, to generate credits to use at other of its refineries or to sell. A strong market for benzene as a petrochemical feedstock may well provide additional incentive for extracting additional benzene at some refineries. Thus, although some refiners in some areas may choose not to reduce benzene further under the final benzene control program, we think it is likely that an overall reduction in gasoline benzene levels will result in all areas of the country.

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[3] See Sierra Club v. EPA, 353 F. 3d 970, 986 (D.C. Cir. 2004) ("[t]his court has adopted an 'every tub on its own bottom' approach to EPA's setting of standards pursuant to the CAA, under which the adequacy of the underlying justification offered by the agency is the pertinent factor – not what the agency did on a different record concerning a different industry")

We are thus finalizing the 0.62 vol% standard as proposed. We believe that this average benzene standard of 0.62, in the context of the associated ABT program and the 1.3 vol% maximum average standard, achieves the greatest reductions achievable, taking into account cost and the other statutory factors in CAA 202(l)(2).

4.1.1.2 Average Standard of 0.62 Vol% Is Too Stringent

What Commenters Said:

Several commenters, all of which are refining companies, commented that they believe that the 0.62 vol% average benzene standard would create serious financial and technical burdens on them and that a less stringent standard should be adopted. The Ad Hoc Coalition of Small Refiners indicated that it was not clear that it will be possible for all of its members to produce market-grade gasoline that meets a 0.62 vol% standard. Two individual refiners commented that it may not be possible for them to meet 0.62 vol%, even using benzene saturation equipment.

Several other refiners made statements that while technologically feasible, the proposed standard would create various technical challenges at their refineries. These refiners mentioned the need for additional capital investment; the inability to pursue benzene extraction as a control option due to lack of proximity to benzene chemical markets; challenges in recovering octane value; the lack of corresponding economic benefit to benzene related improvements; and the challenge of less hydrogen production when controlling benzene. In addition, one company that imports gasoline indicated that a standard of 0.62 vol% may limit the volume of imported gasoline, increase its cost, and adversely affect importers, suggesting that a standard of 1.0 vol% would be more appropriate.

Our Response:

The commenters stating that the 0.62 vol% average standard is too stringent did not address or did not give sufficient emphasis to the fact that no refiner will be required to produce gasoline at the 0.62 vol% level. Even with the addition of the 1.3 vol% maximum average standard, the ABT program will allow refiners that produce gasoline at levels of 1.3 vol% or less to be able to comply with the 0.62 vol% standard by using credits. By combining operational changes, capital equipment, and the use of credits, we believe all refineries will be able to comply with the average standard (and the maximum average standard) within the time available. Should these assumptions prove unfounded, and an individual refiner demonstrates extreme hardship in meeting either of the benzene standards, relief via a hardship variance is available on a case-by-case basis (see section 80.1335). Moreover, if a small refiner demonstrates that the ABT program is not functioning as expected and meeting the 0.62 vol% standard via credits creates extreme hardship (e.g., sufficient credits are for some reason not available or are prohibitively expensive), the refiner may apply for case-by-case hardship relief under section 80.1343.

We do not believe that the technical issues raised by the commenters warrant a change in the proposed average standard. We agree that each of the circumstances presented by the commenters is likely to occur, and we account for them in our modeling and discuss them in the preamble (section VI) or in the RIA (Chapter 6). We believe that such circumstances will rarely if ever cause extreme hardship, especially since refiners must physically produce gasoline only at a 1.3 vol% level or less, not a 0.62 vol% level.

Regarding the comment about negative impacts of the proposed program on the importing of gasoline, we agree that the cost of imported gasoline will rise with the cost of gasoline refined domestically. However, the requirements of the program are essentially identical for both refiners and importers, and we expect that the relative positions in the market between refiners and importers will not change substantially.

4.1.1.3 The Proposed Program Would Affect Geographic Equity in Gasoline Benzene Levels

What Commenters Said:

Several commenters state that the proposed program would maintain or create inequities in gasoline benzene levels from one part of the country to the other, stating or implying that the program should reduce or eliminate such inequities. These commenters attribute these inequities to the nature of the 0.62 vol% standard as an average, which through trading of credits that will occur under the ABT program will allow for variations in gasoline benzene levels across the country. Especially in the absence of an upper limit on benzene, these commenters are concerned that benzene levels in some areas will not be reduced, or may increase, including areas that currently have the highest benzene levels. Some of these commenters specifically indicated that certain areas would have what they believe to be unacceptably high gasoline benzene levels after the proposed program was implemented. One commenter believes that the program should reduce benzene levels to the lowest levels achievable nationally, regionally, and locally.

Our Response:

Our updated analysis shows that with the 0.62 vol% average standard and the maximum average benzene standard of 1.3 vol%, benzene levels will be reduced very significantly in all parts of the country. However, a degree of variation will continue to exist, due to the wide variety of refinery configurations, crude oil supplies, and approaches to benzene control, among other factors. This remaining variation is clearly legally permissible, because we do not read CAA section 202(l)(2) as requiring uniform gasoline benzene levels in each area of the country, since the standard is to be technology-based considering costs and other factors which vary considerably by region and by refinery. On the other hand, the maximum average standard will have the appropriate effect of directionally providing a greater degree of geographic uniformity of gasoline benzene levels and these levels remain feasible achievable considering cost and the other enumerated factors. The program adopted here achieves both national and regional reductions by means of a national standard resulting in greatest aggregate emissions reductions (the annual average standard with ABT), plus a maximum average standard to assure optimization of reductions in all areas. It is reasonable to adopt these standards together here, given the rather large initial disparities in initial benzene levels across fuel regions. Seeking some degree of geographic uniformity in gasoline benzene levels is within the Administrator's discretion, given that section 202 (l) (2) does not specify whether maximum achievable reductions are to be achieved nationally, regionally, or both. The effect of the program on geographic variability in benzene levels is discussed in section VI of the preamble and Chapter 9 of the RIA.

4.1.1.4 Consideration of an Upper Limit Benzene Standard

What Commenters Said:

Several individual refiners and representatives of refiners supported the proposed program's approach of an average standard without a separate upper limit standard. Generally, these commenters supported a program without either a per-gallon cap standard or a maximum average standard, although some of them indicated that a per-gallon cap standard would be more problematic than a maximum average standard. None of these commenters provided analysis or data about the potential effects if an upper limit standard were added.

The Ad Hoc Coalition of Small Business Refiners expressed serious concern about the addition of a maximum average standard. They stated that with a maximum average standard of 1.3 vol%, at least several small refiners would be required to install capital equipment at very significant cost. They maintained that including a maximum average standard creates no additional benzene reduction while increasing compliance costs (citing EPA's analysis at proposal in support). Again citing analysis from the proposed rule, they maintained that including a maximum average would simply shift emission reductions from one region of the country to another, again in their view, imposing costs without any emission reduction benefit. Finally, they advanced the legal argument that imposition of a 1.3 vol% maximum average without consideration of the costs on each refinery violates section 202(l) of the Act, which requires EPA to take costs into consideration in determining maximum degree of emission reduction achievable. They urged EPA not to implement a maximum average standard, and, if it did, to include provisions to allow small refiners to comply with the standard using credits. They suggested alternatives for how such a provision might be structured, either by restricting credits used to meet the 1.3 vol% standard to the PADD in which the refiner is located, or discounting credits used to meet the 1.3 vol% standard.

Most comments from state and local air pollution agencies, environmental/public health organizations, and private citizens supported the addition of an upper limit standard. Several commenters supported a per-gallon benzene cap. Others supported a maximum average standard. Most of the commenters supporting a maximum average standard, including joint comments from four U.S. Senators from the northwest U.S., specified a value of 1.3 vol%, and one commenter supported a maximum average standard of 0.78 vol%. These commenters referred to EPA's analyses of these levels in the proposal, and did not present any additional analytical support. Finally, we received similar comments from approximately 1,000 individual citizens who generally supported an upper limit. These commenters gave two primary reasons for their support of upper limit standards: that an upper limit would provide more certainty that most refineries would reduce benzene levels and would not increase them, and that variations in benzene levels would be reduced or eliminated. Most of these commenters also pointed to EPA's NPRM analysis showing that the estimated average industry-wide costs of adding an upper limit standard would not be large.

Our Response:

Upper Limit Benzene Standard

In the proposal, we considered the implications of an upper limit on the actual level of benzene in the gasoline that refiners produce (as opposed to the level achieved using credits) (see 71 FR 15868-69.) We considered an upper limit both in the form of a per-gallon benzene cap and a limit on the average of actual benzene in gasoline produced by a refinery ("maximum average standard"). Of these two approaches, we recognized that a per-gallon cap would be the more rigid. If every batch needed to meet the cap, there would be no opportunity to offset benzene spikes with lower-benzene production at other times. Even during times of normal operation, our review of refinery batch data indicated that unavoidable wide swings commonly occur in the benzene content of gasoline batches, even for refineries that have relatively low benzene levels on average. A per-gallon cap could result in refiners halting gasoline production during short-term shut-downs of benzene control equipment or in other temporary excursions in benzene levels. Unless a per-gallon limit were generous enough or included case-by-case exceptions (eroding the possible benefit of the cap), many refiners would likely need to implement much deeper and more costly reductions in benzene than would otherwise be necessary, simply to protect against such fluctuations. For some refiners, we tentatively concluded, a cap could make complying with the program prohibitively expensive.

The other option on which we solicited comment, a maximum average standard, would be more flexible. A maximum average standard would limit the average benzene content of the actual production at each refinery over the course of the year, regardless of the extent to which credits may have been used to comply with the 0.62 vol% average standard. Thus, a maximum average standard would allow for short-term benzene fluctuations as long as the annual average benzene level of actual production was less than that upper limit.

After evaluating the results of our updated refinery analysis and considering all of the comments, we now believe that the program should include a maximum average benzene standard set at an appropriate level. The maximum average standard has the strong advantage of ensuring that the benzene content of gasoline produced by each refinery (or imported by each importer) will average no higher than that level, regardless of the use of credits, providing greater assurance that actual in-use benzene reductions more clearly reflect our modeled projections which form the basis for this rule. At the same time, the maximum average standard avoids the serious drawbacks of a per-gallon cap.

As explained in section VI.A.1.d of the preamble to the final rule, while we have used all information available to us, our modeling cannot predict with high confidence each individual refinery's actions and how benzene trading will occur in all cases. Thus, although our analysis at proposal indicated widespread reductions in gasoline benzene levels in all fuel regions (notwithstanding that any individual refinery could avoid benzene reductions through credit purchases), we cannot dismiss with high confidence the possibility voiced in the comments that significant disparities in gasoline benzene levels will remain. Consequently, we are adding an upper limit to the 0.62% average standard in order to provide greater assurance that the benzene emission reductions we project, including their uniform distribution, are actually achieved. By selection of an appropriate level for the maximum average, the program will achieve these important benefits with a very small impact on the program's overall cost.

We have chosen a level of 1.3 vol% for the maximum average standard. We believe this level represents a reasonable balance between the additional cost and increased confidence in the occurrence of expected gasoline benzene reductions in all fuel regions. Implementing an upper limit below 1.3 vol% would increase the number of refineries needing to install the most expensive benzene reduction equipment, thus diminishing the flexibility of the ABT program and increasing the cost of the program. Conversely, an upper limit above 1.3 vol% would have only limited effectiveness in ensuring that the modeled benzene gasoline levels are achieved in the long term. .

We carefully considered the comments of small refiners regarding a maximum average standard. We do not accept the position that a maximum average standard imposes costs without emission reduction benefits. As stated in response 4.1.1.3 and the preamble to the final rule, the maximum average requirement assures that predicted reductions in gasoline benzene levels across all PADDs will in fact occur. As further stated, this assures that maximum achievable reductions will occur both nationally and regionally, a reasonable objective. We also no longer believe that the effect of a maximum average cap will be merely to redistribute benzene gasoline levels. We tentatively reached that conclusion at proposal based on refinery-by-refinery modeling that among other things assumed a precisely linear response between the level of standards and the volume of credits generated. This assumption is not a given, since (among other things) refineries may in fact decide to overcomply with the annual average standard for reasons other than credit generation, such as assuring a compliance safety margin. More generally, we now believe that the predicted offsetting effects are too small relative to the accuracy of the predictive model for us to have certainty they will occur.

Small refiners further argued that EPA has ignored costs to each refinery in adopting the maximum average standard, and that this violates the requirement in section

202(l)(2) to consider costs in determining maximum emissions reductions achievable. The statute does not specify how costs are to be considered, and so does not require refiner-by-refiner cost determinations. Our approach to considering cost in this rule is well within the ample discretion the statute affords. We considered costs to the refining industry overall and on an aggregate cost per gallon of gasoline basis, and conducted the same analysis on a PADD by PADD, and refiner-by-refiner basis. As explained in detail in chapters 9 and 14 of the final RIA, although not every refiner will incur the same cost impacts under the rule, we believe that the overall costs of complying with the rule are reasonable. As explained in those same sections, we believe that the rule is also technically feasible at reasonable cost for all refiners. In addition, if economic impacts on individual refiners are more severe than expected, the rule includes safety valve provisions whereby refiners can obtain relief by demonstrating significant economic hardship.

Several commenters supported an upper limit standard as a way of reducing the variation in benzene levels that currently exist across the country. We agree that reducing gasoline benzene levels on both a national and regional basis is a reasonable objective, as discussed in section 4.1.1.3 above, and further agree that implementing the overall program (including the maximum average standard) will have the effect of reducing variability in gasoline benzene levels, as also discussed in that response.

We discuss in more detail our rationale for adding a maximum average standard, and for our selection of the level of 1.3 vol% for that standard, in section VI of the preamble for this final rule.

<u>Letters relating to Section 4.1.1:</u>
Ad Hoc Coalition of Small Business Refiners OAR-2005-0036-0686
Alaska Department of Environmental Conservation, Division of Air Quality (ADEC) OAR-2005-0036-0975
American Lung Association OAR-2005-0036-0365 (Hearing testimony)
(Municipality of) Anchorage, Department of Health and Human Services OAR-2005-0036-0976
Citizen comments OAR-2005-0036-1019 (generally representative of approximately 1,000n citizen comment letters)
Colonial Oil Industries, Inc. OAR-2005-0036-0990
Countrymark Cooperative, LLP OAR-2005-0036-0471
Environmental Defense, NRDC, U.S. PIRG, ALA OAR-2005-0036-0868
ExxonMobil Refining & Supply Company OAR-2005-0036-0772
Flint Hills Resources, LP (FHR) OAR-2005-0036-0862
Lane Regional Air Protection Agency (LRAPA) OAR-2005-0036-0848
Marathon Petroleum Company LLC OAR-2005-0036-1008
National Petrochemical & Refiners Association (NPRA) OAR-2005-0036-0809
New Jersey Department of Environmental Protection, Division of Air Quality (NJ DEP) OAR-2005-0036-0829
New York Department of Environmental Conservation OAR-2005-0036-0722
NESCAUM OAR-2005-0036-0993

Oregon Department of Environmental Quality (OR DEQ) OAR-2005-0036-0987
Oregon Toxics Alliance (OTA) OAR-2005-0036-0948
Private Citizen OAR-2005-0036-0368
Puget Sound Clean Air Agency OAR-2005-0036-0780
Silver Eagle Refining, Inc. OAR-2005-0036-0839
Sinclair Oil Corporation, Flying J. Inc., Suncor Energy (U.S.A.) Inc., and Tesoro Corporation OAR-2005-0036-0989
STAPPA/ALAPCO OAR-2005-0036-0836
United Refining Company OAR-2005-0036-0827
U.S. Senator Ron Wyden et al
Washington State Department of Ecology OAR-2005-0036-0950.1
Wisconsin Department of Natural Resources, Bureau of Air Management (WDNR) OAR-2005-0036-0828

4.1.2 Consideration of Other Fuel Controls

4.1.2.1 Consideration of a Total Toxics Performance Standard

What Commenters Said:

Several commenters, primarily individual refining companies and organizations representing refining companies, supported the proposed benzene control approach of focusing on gasoline benzene content rather than on total toxics emissions. Generally, they stated that the proposed benzene content standard would result in the same toxics emissions benefits (since refiners would meet a toxics standard through benzene control anyway), and they support the simplification in gasoline toxics regulation that the proposed program would represent.

On the other hand, many commenters supported an MSAT program that includes a total toxics standard, either in addition to or instead of an average benzene standard. In general, these comments express concern that the lack of a total toxics performance standard could allow refiners to increase other MSATs even while reducing benzene. One commenter pointed out that EPA made similar arguments in support of the MSAT1 program.

<u>Letters:</u>
American Petroleum Institute (API) OAR-2005-0036-0884
American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA) OAR-2005-0036-1015
BP Products North America Inc. OAR-2005-0036-0824
ExxonMobil Refining & Supply Company OAR-2005-0036-0772
Flint Hills Resources, LP (FHR) OAR-2005-0036-0862
Independent Fuel Terminal Operators Association OAR-2005-0036-1007
Marathon Petroleum Company LLC OAR-2005-0036-1008
National Petrochemical & Refiners Association (NPRA) OAR-2005-0036-0809

New Jersey Department of Environmental Protection, Division of Air Quality (NJ DEP)
OAR-2005-0036-0829
NESCAUM OAR-2005-0036-0993
Puget Sound Clean Air Agency OAR-2005-0036-0780
Regional Air Pollution Control Agency (RAPCA) OAR-2005-0036-0771
Sunoco, Inc. OAR-2005-0036-0806
United Refining Company OAR-2005-0036-0827
Washington State Department of Ecology OAR-2005-0036-0950
Wisconsin Department of Natural Resources, Bureau of Air Management (WDNR)
OAR-2005-0036-0828

Our Response:

For several reasons, we continue to believe that a benzene-only standard is superior to a toxics emissions performance standard as a means of achieving the greatest emission reductions of mobile source air toxics under section 202(l). First, because controlling benzene is much more cost-effective than controlling emissions of other MSATs, refiners historically have preferentially reduced benzene under the MSAT1 and other air toxics control programs. This is despite the theoretical flexibility that refiners have under a toxics performance standard to change other fuel parameters instead of benzene. Thus, even if we were to express the proposed standard as a total air toxics performance standard, we would expect the outcome to be the same – refiners would reduce benzene content and leave unchanged the levels of other MSATs. Many industry commenters confirmed this point in their comments on the proposed rule.

Second, even with, or as a result of, this fuel benzene control, we do not expect refiners to actively modify their refinery operations such that increases will occur in emissions of the other MSATs currently controlled under the existing toxics performance standards. These other MSATs are acetaldehyde, formaldehyde, POM, and 1,3-butadiene, and they are all affected to varying degrees by VOC emissions control. VOC emissions are generally decreasing due to the gasoline sulfur controls recently phased in along with more stringent vehicle controls under the Tier 2 program, as well as the vehicle controls being finalized under this program (see section V of the preamble). In combination, these changes are expected to decrease VOC-based MSAT emissions substantially.

The one MSAT likely to increase in the future is acetaldehyde. The proposed Renewable Fuels Standard (RFS) Program[4] ensures that ethanol use will increase, and thus acetaldehyde as well, since that MSAT is directly and substantially affected by ethanol use. Acetaldehyde emissions are currently increasing (and formaldehyde emissions decreasing) due to the substitution of ethanol for MTBE in RFG as a result of state MTBE bans. Any action that refiners could take to offset the total toxics increase as a result of acetaldehyde increasing would be through benzene control, which we are already requiring to be controlled to the maximum extent achievable. The EPAct, which charged EPA with developing the RFS program, also requires an evaluation of that Act's

[4] 71 FR 55552, September 22, 2006.

impacts on air quality. Any future control of acetaldehyde emissions will be based primarily on the results of that study, a draft of which is required by the EPAct to be completed in 2009. EPA thus believes it is premature to act on this issue until we determine a course of future action reflecting the EPAct study.

With the exception of acetaldehyde, the benzene control program will ensure the certainty of additional reduction in MSAT emissions, and other MSAT emissions are unlikely to increase under this program. We therefore believe that regulatory controls and the associated paperwork and other administrative costs for these other MSATs, including a total toxics standard, are not necessary. A toxics emissions performance standard that would effectively achieve the same level of MSAT reduction would just be more costly and complex. We see no justification for the added complexity, paperwork, and other administrative costs of a total toxics standard. For all of these reasons, we believe a standard in the form of a benzene content standard will produce more certain environmental results with less complexity than a toxics emissions performance standard, and we are therefore finalizing only a benzene content standard.

As one commenter pointed out, this conclusion is different from that reached in the MSAT1 final rule (66 FR 17230, March 29, 2001). However, there are several reasons for a different decision here. First we have gained much more experience in witnessing refiner actions and behavior following the implementation of the MSAT1 standard (notably their reliance on benzene reductions to satisfy the MSAT1 standard). Second, several changes to the fuel pool have occurred which constrain the ability of refiners to adjust toxics performance in ways other than changing benzene content, most notably the removal of both MTBE and sulfur from gasoline. Third, the MSAT2 standards require significant reductions in MSAT levels, whereas the MSAT1 standards were merely meant to maintain existing performance. To reduce toxics, it is clear that benzene is now a refiner's only viable option, and a benzene-only standard is thus the most effective regulatory approach.

4.1.2.2 Consideration of Regulation of Other MSATs

What Commenters Said:

In addition to comments expressing concern that MSATs other than benzene might increase in the absence of a toxics performance standard (see previous section), some commenters urged specific regulatory action to reduce some of these MSATs. One commenter advocated adoption of key parameters of California's Reformulated Gasoline III specifications (aromatics content, olefins content, and sulfur). Various commenters expressed concern about e 1,3-butadiene, acrolein, acetaldehyde, and formaldehyde. Another commenter believes that it is premature to limit MSAT regulation to benzene alone, and encouraged EPA to specifically remain open to prompt further regulation of other MSATs if future changes to gasoline parameters do not address them. The commenter provided naphthalene and gasoline PM as potential examples. Another commenter encouraged EPA to continue to develop comprehensive data on toxics emissions from Tier 2 vehicles so that greater confidence can be placed in analyses performed using the Complex Model.

One commenter specifically supported EPA's decision not to propose further control of POM, 1,3-butadiene, formaldehyde, acetaldehyde, and gasoline aromatics content.

Letters:
Environmental Defense, NRDC, U.S. PIRG, ALA OAR-2005-0036-0868
Marathon Petroleum Company LLC OAR-2005-0036-1008
New Jersey Department of Environmental Protection, Division of Air Quality (NJ DEP)
OAR-2005-0036-0829
Puget Sound Clean Air Agency OAR-2005-0036-0780
Wisconsin Department of Natural Resources, Bureau of Air Management (WDNR)
OAR-2005-0036-0828

Our Response:

In the previous section and in section VI of the preamble, we lay out our reasons for believing that the final program (without a toxics performance standard) will not result in increases in MSATs other than benzene. This same reasoning supports our conclusion that further regulation of any of these MSATs is not appropriate at this time. The Agency remains open to any new information that might indicate that future regulatory action on other MSATs is warranted. Moreover, as indicated in the previous response, EPA will specifically consider the effect of acetaldehyde emission as part of the study mandated by the EPAct.

As the one commenter stated, current emission models would suggest that California gasoline may provide somewhat greater toxics performance than the benzene standard we are finalizing. However, considering the limited data on new technology vehicles with which to quantify these emission reductions, and the far greater cost of such fuel changes, we do not believe such requirements would be appropriate at this time.

4.1.2.3 Control of Aromatics

What Commenters Said:

Several commenters specifically stated that aromatics in gasoline (other than benzene) should be targeted for control in this rule. Most of these commenters pointed to the fact that toluene and xylene (some also mentioned ethyl benzene) are also considered MSATs and their content in gasoline should be reduced. Some commenters also mentioned the connection between aromatics and secondary (atmospherically formed) PM. Two commenters, the Energy Future Coalition (EFC) and TEIR Associates, compiled several existing studies and expressed their belief that replacing aromatics can be broadly replaced with ethyl tertiary butyl ether (ETBE), an ether produced from ethanol. API and NPRA responded to the EFC and TEIR comments with supplemental comments that countered several points. These organizations also raised concerns about potential groundwater contamination from ETBE, as has occurred with the ether MTBE.

Other commenters, mostly from the refining industry, oppose new controls on gasoline aromatics at this time, generally agreeing with EPA that it is not yet clear that such controls would be cost-effective.

Letters:

American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA) OAR-2005-0036-1015
Energy Future Coalition OAR-2005-0036-0840
Flint Hills Resources, LP (FHR) OAR-2005-0036-0862
Mothers & Others for Clean Air OAR-2005-0036-0991
New Jersey Department of Environmental Protection, Division of Air Quality (NJ DEP) OAR-2005-0036-0829
New York Department of Environmental Conservation OAR-2005-0036-0722
NESCAUM (Northeast States for Coordinated Air Use Management) OAR-2005-0036-0993
TEIR Associates, Inc OAR-2005-0036-0838
TEIR Associates, Inc. OAR-2005-0036-1012

Our Response:

EPA considered the potential for additional aromatics control as a part of the proposed rule (see 71 FR 15864). We have considered the issue further in light of the public comments. For the following reasons, we continue to believe that additional aromatics control (beyond the benzene control of this rule and beyond the reduction in gasoline aromatics that we believe will occur without further action) is unwarranted at this time. We will continue to investigate this area, as described below and in section VI of the preamble.

We note first that regardless of specific regulatory action to control aromatics, the increased use of ethanol in response to current market forces and federal and state policies (including the RFS program) will contribute to lower aromatics levels. This will occur for two reasons. First, ethanol has historically been blended downstream of refineries, either as a "splash blend" or as a "match blend." In a splash blend, the ethanol is mixed with finished gasoline. In a match blend, refiners prepare a special subgrade of gasoline that, when blended with ethanol, becomes finished gasoline. In recent years, match blending has increased as refiners have been producing RFG with ethanol, and it is expected to increase even more as ethanol use expands. A splash blend will reduce aromatics by about 3 vol% by simple dilution.[5] A match blend will reduce aromatics by

[5] If the aromatics content of a gallon of gasoline is 30 vol%, adding 10% ethanol dilutes the aromatic content to about 27 vol%.

about 5 vol%.[6] With ethanol use expected to more than double, we expect a significant reduction in aromatics levels. Second, with all of this ethanol there will be excess octane in the gasoline pool. Thus, not only will increased ethanol use decrease aromatics concentrations through dilution, but refiners will make the economic decision to use ethanol to reduce or avoid producing aromatics for the purpose of increasing octane.

Because of differences in how refiners will respond to the rapid increase in ethanol use, it would be difficult to determine an appropriate level for an aromatics standard at this time. The gasoline market is going through an historic transition now due to the removal of MTBE, some portion of the MTBE production volume being converted to other high octane blendstock production, the growth of ethanol use, and the rise in crude oil prices. Consequently, it is difficult to reliably project a baseline level for the aromatics pool with any confidence. This is compounded by a great deal of uncertainty in knowing how much of the market ethanol will capture. Projections by EIA are significantly higher now than just a few months ago, and Presidential and Congressional proposals could easily result in 100% of gasoline being blended with ethanol. Second, aromatics levels vary dramatically across refineries based on a number of factors, including refinery configuration and complexity, access to other high octane feedstocks, access to the chemicals market, crude sources, and premium grade versus regular grade production volumes. Third, without knowing with some certainty the range of aromatics contents of refineries' gasoline, we cannot determine the greatest degree of emission reduction achievable, and also cannot make reasonable estimates regarding cost, lead time, safety, energy impacts, etc. As a result, at this time we would not be able to determine an appropriate or meaningful aromatics standard.

For the purpose of reducing total toxics emissions, fuel benzene control is far more cost-effective than control of total aromatics, for a number of reasons. As we explained in the proposal, reducing the content of other aromatics in gasoline is much less effective in reducing benzene emissions than reducing fuel benzene content. Based on the Complex Model, [7] roughly 20 times greater reduction in total aromatics content is needed to achieve the same benzene emission reduction a is achieved by a fuel benzene reductions. At the same time, to broaden the program to control other aromatics would result in a significant octane loss that would be difficult and costly to replace. While we have not yet conducted a thorough refinery modeling evaluation, based on existing refinery and market information the alternative sources of octane (other than ethanol) appear to be of limited supply and would be of limited effectiveness in replacing the octane lost from any fuel aromatics reductions. Furthermore, as noted above, the uncertainty in the extent to which ethanol will penetrate the market makes it difficult to project the potential replacement of aromatics with ethanol. Any significant reduction in

[6] Section 2.2 "Effects of Ethanol and MTBE on Gasoline Fuel Properties" in the Renewable Fuel Standard Program: Draft Regulatory Impact Analysis, September, 2006.

[7] Total toxics emissions are as calculated by the Complex Model. This model is the tool used to determine compliance with the toxics emissions controls in the RFG, Anti-dumping, and MSAT1 programs. Cost estimates for aromatics control and analysis of relative benzene emissions with control of aromatics and benzene are found in Regulation of Fuels and Fuel Additives; Standards for Reformulated and Conventional Gasoline; Final rule, Table VI-A6 of the Regulatory Impact Analysis, February 16, 1994.

aromatics would also affect the gasoline and diesel sulfur reduction programs because hydrogen, which is used in the desulfurization.

Reducing aromatics would also raise other environmental concerns that would need to be addressed in any regulation. Actions available to refineries for replacing octane, including adding ethanol, can increase other MSATs, as mentioned above. In addition, some commenters encouraged the use of the ether derived from ethanol, ETBE, to make up octane. Any regulatory action that required or was based on the use of ETBE would likely raise issues of potential groundwater contamination given the groundwater contamination caused by the use of the chemically similar MTBE.

There may be compelling reasons to consider aromatics control in the future, especially regarding reduction in secondary $PM_{2.5}$ emissions, where evidence supports a role for aromatics in secondary $PM_{2.5}$ formation.[8] Unfortunately, there are limitations in both primary and secondary PM science and modeling tools that limit our present ability to quantitatively predict what would happen for a given fuel control. Thus, at this point, we do not feel that the existing body of information and analytical tools provide a sufficient basis to determine if further fuel aromatics control is warranted. However, we do feel that additional research is very important. Test programs and analyses are planned to address primary PM issues, including those examining the role of aromatics. Also, more work is underway on how fuel aromatics, including toluene, affect secondary PM formation, and how aromatics control should be incorporated into air quality predictive models.[9]

In summary, we believe that aromatics levels will be falling even without an aromatics standard, and aromatics control will need to be evaluated in the context of what might be possible beyond what will occur through the expanded use of ethanol. In addition, any additional control would be costly and raise a number of other issues which need further investigation before EPA could responsibly initiate such a control effort. Thus, we have concluded that additional aromatics control for MSAT purposes is not warranted at this time.

4.1.2.4 Gasoline Sulfur, RVP, and Other Fuel Properties

What Commenters Said:

Petroleum industry comments related to sulfur control generally expressed the position that additional control would require expensive upgrades to billions of dollars worth of equipment just installed for the 30 ppm sulfur standard, and yet would not produce any significant toxics reductions. Auto industry comments suggest that measurable emission reductions in HC and MSAT emissions could be had by lowering gasoline sulfur below 10 ppm, and Toyota submitted a small amount of data to support this. Comments from state and local governments and environmental/public interest

[8] See Chapter 1 in the RIA for more on current studies on this subject.
[9] See Chapter 1 in the RIA for more on current studies on this subject.

groups state that EPA has a duty to require the greatest emissions control achievable, and that lower sulfur gasoline is achievable since the state of California has a more stringent standard. These comments also state that EPA's analysis of the benefits of low sulfur gasoline were inadequate, and echo the auto industry comments that low sulfur gasoline will reduce HC and MSAT emissions. There were also comments stating that EPA had not considered distillation parameters and increased detergency as viable ways to reduce hydrocarbon emissions, in turn reducing emissions of MSATs.

Comments specifically related to more stringent gasoline volatility control came only from the petroleum industry, and highlighted negative impacts on gasoline supply that could result. The commenters explained that any additional butanes and pentanes removed during the summer season would likely exceed refiners' ability to store and re-blend the material back into winter gasoline due to volatility limits on winter gasoline. One commenter also supported the position that further volatility control would not reduce MSAT emissions to a significant extent.

Letters:

Alliance of Automobile Manufacturers (Alliance) OAR-2005-0036-0881
American Petroleum Institute (API)
American Lung Association OAR-2005-0036-0365 (hearing testimony)
Countrymark Cooperative, LLP OAR-2005-0036-0471
Environmental Defense, NRDC, U.S. PIRG, ALA OAR-2005-0036-0868
Flint Hills Resources, LP (FHR) OAR-2005-0036-0862
Independent Fuel Terminal Operators Association (IFTOA) OAR-2005-0036-1007
Nissan Technical Center North America (Nissan) OAR-2005-0036-0825
Toyota Technical Center (TTC) OAR-2005-0036-0773

Our Response:

At the time of the proposal, we did not have adequate data to fully evaluate additional gasoline sulfur reduction or further volatility control as MSAT reduction strategies (and the data submitted by Toyota consisted of a very small number of tests). Since the proposal, we have completed a small fuel effects test program in cooperation with several automakers to help evaluate the usefulness of fuel property changes as emission controls on Tier 2 vehicles. These data suggest that reducing gasoline sulfur to a level of 6 ppm would bring reductions in regulated criteria pollutants, but not in total toxics as defined by the Complex Model. The data also suggest that reducing gasoline volatility from 9 to 7 RVP under normal testing conditions (75°F) may actually increase exhaust emissions of several air toxics. The test program did not examine the impacts of fuel volatility on evaporative emissions. We will be using this and other data as it becomes available to consider future action on further gasoline sulfur control. More details on the test program and its results are available in Section 6.11 of the RIA.

For MSAT control programs, the Clean Air Act requires EPA to consider technological feasibility as well as cost and other factors. We believe there would be significant costs in requiring another large step down in sulfur below the recently implemented standard of 30 ppm, costs far greater than those associated with incrementally more stringent average benzene standards, which we concluded in this rule would be unreasonable. While we can not rule out further action on gasoline sulfur levels in the future, much more testing and analysis would be required before EPA would propose such action. Furthermore, refineries are in the process of implementing the gasoline sulfur control standards associated with the Tier 2 program, the on-highway diesel rule, and the nonroad diesel rule. EPA considers it unreasonable to potentially interfere with the implementation of these important standards by adopting another desulfurization standard to apply in much the same time frame (see Sierra Club, 325 F. 3d at 380). Until EPA can more fully evaluate the real-world impacts of these rules on refineries, it is unreasonable to adopt a further standard for gasoline sulfur.

4.1.2.5 Diesel Fuel

What Commenters Said:

One group of commenters stated in joint comments that they believe that EPA needs to do more to protect human health and the environment from the effects of diesel exhaust emissions. While they specifically mention actions to accelerate the introduction of cleaner diesel engines, they do not suggest any additional changes to diesel fuel. Some commenters noted that polyaromatic hydrocarbons (PAHs) and nitro-PAHs are a particularly harmful component of diesel exhaust, and support control of these emissions either directly or through control of PAH content in diesel fuel. Another commenter, a refiner, states that further diesel fuel controls are not warranted.

Letters:
Environmental Defense, NRDC, U.S. PIRG, ALA OAR-2005-0036-0868
ExxonMobil Refining & Supply Company (XOM) OAR-2005-0036-0772
International Truck and Engine Corporation (International) OAR-2005-0036-0826
Marathon Petroleum Company LLC OAR-2005-0036-1008
New York State Department of Environmental Conservation OAR-2005-0036-0722

Our Response:

EPA did not propose additional controls on diesel exhaust emissions or diesel fuel for MSAT control. We believe that existing EPA regulations for highway and nonroad diesels will achieve the greatest reductions currently achievable in MSAT emissions from diesel engines. The actions refiners are taking to produce ultra-low sulfur diesel fuel (15 ppm sulfur) are expected to reduce the PAH content in diesel fuel.[10] In addition, available data indicate that the advent of exhaust emission controls on diesel engines under the recent diesel programs will reduce exhaust PAH, regardless of any changes to diesel fuel. As the content of PAHs in the fuel as well as the amount emitted in engine

[10] Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel – Final Rule, Section 5.9.4 of the Regulatory Impact Analysis, June 29, 2004.

exhaust decreases, emissions of nitro-PAHs will also decrease due to decreases in the precursor PAH emissions.

EPA will continue to monitor MSAT issues related to diesel engines and fuel. For example, there is a large program from the Health Effects Institute (HEI) just starting to characterize regulated and unregulated emissions (and their health effects) from engines meeting the 2007 and 2010 emission standards, including measurement of many PAH and nitro-PAH compounds.[11] This project has numerous sponsors, including EPA.

In conclusion, existing diesel regulations will reduce PAH (and nitro-PAH) emissions. At this time, we are not aware of further diesel fuel controls that could significantly affect MSAT emissions and commenters did not offer specific information to the contrary. Consequently, we have focused our fuel-related MSAT action on gasoline benzene, as proposed, while continuing our efforts to better quantify the reductions in PAH (and nitro-PAH) emissions from diesel engines meeting the 2007 and 2010 standards.

4.2 Implementation Issues

4.2.1 Replacement of Existing Standards

What Commenters Said:

A number of commenters supported the proposal to consolidate and simplify the regulatory provisions by using the Tier 2/Gasoline Sulfur rules as the sole regulatory mechanism for implementing the RFG and anti-dumping NOx requirements, and the proposed benzene rule as the sole regulatory mechanism for implementing the RFG and anti-dumping toxics requirements. In addition, in light of the proposed benzene standard, some commenters stated their support for the elimination of the MSAT1 requirements, and for avoiding adjusting the RFG MSAT1 baselines as required by EPAct absent a more stringent toxics program. Several commenters added that they believe this proposal is an excellent example of reducing the regulatory burden by removing regulations that are no longer needed because of changed circumstances. Some commenters pointed out that the Agency has the opportunity to reduce the considerable compliance and enforcement burden placed on it, as well as on the industry. At least one commenter noted that these rule simplifications will not result in any environmental degradation, and another noted that the removal of requirements made obsolete by instituting the MSAT2 program will reduce the chances that this additional requirement will further constrain gasoline production.

Other commenters stated that they do not believe that EPA should revoke the MSAT1 anti-backsliding and anti-dumping provisions, and urged EPA to retain the RFG and anti-dumping NOx performance standards rather than rely on the federal gasoline sulfur program. One of these commenters stated that EPA's justification for this proposed

[11] Advanced Collaborative Emission Study, Health Effects Institute, Cambridge, MA.

action was too brief, and that in any event such action is not appropriate for this MSAT-related rulemaking.

Letters:
American Petroleum Institute (API) OAR-2005-0036-0366, 0367
BP OAR-2005-0036-0824, 0837
Chevron Corporation (Chevron) OAR-2005-0036-0847
ExxonMobil OAR-2005-0036-0772, -1013
Flint Hills Resources, LP (FHR) OAR-2005-0036-0862
Marathon Petroleum Company, LLC (MPC) OAR-2005-0036-1008
National Petrochemical Refiners Association (NPRA) OAR-2005-0036-0809
New York State Department of Environmental Conservation (NY DEC) OAR-2005-0036-0722
Northeast States for Coordinated Air Use Management (NESCAUM) OAR-2005-0036-0993, -0369
Regional Air Pollution Control Agency (RAPCA) OAR-2005-0036-0771
STAPPA/ALAPCO OAR-2005-0036-0836, -0378

Our Response:

A detailed discussion of how the toxics and NOx requirements for CG and RFG will be met under the MSAT2 program is provided in Chapter 6.12 of the RIA for this rulemaking. Based on analysis of gasoline batch data from recent years as well as our projections of what refiners will be doing to comply with MSAT2, we believe compliance with MSAT2 will reduce air toxics emissions significantly below the MSAT1 baselines as well as below the RFG and anti-dumping toxics requirements. Therefore, these existing regulatory programs will effectively be superseded and become redundant. Since we believe that the benzene program will be significantly more stringent than the existing programs, we are waiving the requirements for demonstration of compliance with previous air toxics programs.

We also believe that the Gasoline Sulfur/Tier 2 program is reducing NOx emissions to a significantly greater degree than are the NOx performance standards for RFG and CG. Gasoline sulfur has the largest impact on NOx emissions in modern vehicles equipped with three-way exhaust catalysts -- now comprising more than 95% of the gasoline fleet -- under the Complex Model used to certify fuel to the NOx standards. Therefore the reduction of gasoline sulfur to 30 ppm average nationwide is causing all gasoline to far exceed the NOx emission performance standards required under the RFG and anti-dumping programs. Given this fact, we believe that the existing regulations have become unnecessary, and we believe that it is appropriate to take action to simplify our regulations to waive requirements for demonstration of compliance with the NOx performance standards for RFG and CG.

In response to the comment about the appropriateness of taking action relating to the sulfur control program in the context of this MSAT-related rule, we disagree. We believe that taking this action is necessary and appropriate now as we are making corresponding changes to the regulations for air toxics performance standards. Initiating a separate rulemaking action for this limited purpose at a later date would be inefficient for EPA and for stakeholders.

4.2.2 Batch by Batch Testing

What Commenters Said:

Several commenters stated that they oppose the requirement to test each batch of conventional gasoline for benzene. These commenters believe every-batch testing will involve unnecessary time and record keeping and will create an unnecessary financial burden for small refiners and blenders. They state that they would prefer to test monthly composite samples since the standard is an annual average and there is no per gallon benzene limit. These commenters also stated that they support the proposed ability for refiners (and importers) to release conventional gasoline prior to getting the results of any benzene testing, because with annual average compliance, there will generally be time to account for off-spec gasoline before the end of the annual reporting period, and thus there is no need to delay deliveries while waiting for test results.

<u>Letters:</u>
Caribbean Petroleum OAR-2005-0036-1010
Colonial Oil Industries, Inc. (Colonial) OAR-2005-0036-0990
Gladieux Trading & Marketing Co., L.P. (Gladieux)OAR-2005-0036-0972
U.S. Oil & Refining, Co. (USOR) OAR-2005-0036-0992

Our Response:

We proposed to require every-batch sampling for CG benzene under this program, (see 71 FR 15893). RFG already is every-batch tested, and the results must be available before the batch leaves the refinery to support effective enforcement of RFG's 1.3 vol% benzene per gallon cap. For CG, we are concerned about the potential for benzene-rich blendstocks to be added downstream, since the new program does not have any downstream testing or reporting requirements. Requiring every-batch testing for CG will allow for closer monitoring of the movement of high benzene streams, and we will be able to better discern if high benzene batches originated at the refinery, or downstream. With composite testing, it would be significantly more difficult to determine the source of any high benzene gasoline found downstream. Thus, we see every-batch testing for all gasoline as a necessary part of the gasoline benzene program.

For CG, every-batch sampling is already required for gasoline sulfur, and will be well under way for small refiners by the time small refiners are required to comply with the benzene program requirements. Thus, there may be a small incremental cost for additional benzene testing for those refiners that currently determine CG benzene levels from a composite sample. However, we do not believe that these additional costs will be large; commenters that raised the issue of this potential additional did not provide any data or analytical support for this concern. We are finalizing every-batch benzene testing for all gasoline.

As we proposed, we are not requiring that the results for CG be available before the batch leaves the refinery, for the reasons given by the commenters.

4.2.3 Reporting, Recordkeeping, Surveys

What Commenters Said:

Several commenters stated that if the Agency deletes MSAT1, RFG NOx and toxics, and anti-dumping NOx and toxics, as proposed, then gasoline batch testing, reporting and recordkeeping regulations must be revised. The commenters stated that they believe that EPA may continue to require sulfur and benzene content testing, reporting and recordkeeping for every gasoline batch, but that there would be no regulatory purpose to continue testing, reporting and recordkeeping for RVP, distillation, olefins, oxygen, and aromatics for CG and for winter RFG. They believe that RVP, distillation, olefins, oxygen and aromatics would only have a regulatory purpose for RFG summer VOC regulatory compliance.

In addition, some of these commenters stated that the RFG NOx and toxics retail survey regulations must be revised. The commenters suggested that, if the MSAT2 benzene standard is effective beginning in 2011, the RFG toxics retail compliance surveys should be discontinued after 2010 because there would not be a RFG toxics emissions standard to "ratchet" down in case of a failure. Similarly, commenters stated that RFG NOx retail compliance surveys should be discontinued because there would not be a RFG NOx emissions standard to ratchet down in case of a failure. These commenters noted that in 2010, the RFG Survey Association will submit a plan for 2011 for EPA approval that excludes toxics, and that the RFG Survey Association will submit a plan for 2007 for EPA approval that excludes NOx.

<u>Letters:</u>
American Lung Association (ALA) OAR-2005-0036-0365 (hearing comments)
Marathon Petroleum Company, LLC (MPC) OAR-2005-0036-1008
National Petrochemical Refiners Association (NPRA) OAR-2005-0036-0809

Our Response:

In the proposal we stated that certain reporting and recordkeeping requirements would be modified or eliminated because of the benzene standard. Compliance with the RFG and anti-dumping toxics standards will be achieved through the benzene control program. In addition, compliance with the RFG and anti-dumping NOx standards will be achieved through the gasoline sulfur program. Because compliance with the toxics and NOx requirements will be achieved through other programs, many of the reporting and recordkeeping requirements are being streamlined by the final rule. However, sampling, testing, and reporting of all of the current fuel parameters will continue to be required. This benzene control program is merely the means by which compliance with the RFG and anti-dumping controls is being measured; the individual rules are still in effect. EPA is obligated to continue to monitor how refiners comply (through fuel composition changes) and how other toxics emissions may be affected by the benzene and gasoline sulfur rules. The Agency's authority to collect information on the fuel parameters that affect the toxics (and NOx) control programs also remains. Continued collection of all of the fuel parameters will facilitate future toxics evaluation activities.

Commenters also suggested eliminating the toxics and NOx retail surveys that are currently carried out for RFG because there would not be RFG toxics or NOx emissions standards to "ratchet" down in case of a failure because the toxics and NOx requirements were being met by the gasoline benzene and sulfur programs. A discussion of the origin of the RFG survey program is included in Chapter 6.12 of the RIA. The surveys use fuel parameters of RFG sampled from retail stations to estimate VOC, NOx, and toxics emissions. There are also fuel benzene and oxygen content surveys. If a survey is "failed," meaning that the survey shows the fuel to be out of compliance, the requirements are "ratcheted down" and gasoline sent to the area must meet a more stringent standard. Because we are finalizing, as proposed, provisions that make the gasoline sulfur program the sole regulatory mechanism used to implement gasoline NOx requirements, and the benzene control program the sole regulatory mechanism used to implement the toxics requirements of RFG[12] and anti-dumping, we agree that the NOx and toxics surveys are no longer needed, and are no longer required.

4.2.4 Accounting for Downstream Oxygenates

What Commenters Said:

Several commenters stated that the current regulatory option to include downstream oxygenate addition in RFG, anti-dumping and MSAT1 compliance calculations should be retained in the MSAT2 program, especially considering the expanding use of ethanol due to the Renewable Fuel Standard in the EPAct. Commenters further noted that since ethanol serves as a diluent, much the way that MTBE has historically, allowing the inclusion of downstream ethanol addition to be included in the calculation is justified.

Another commenter said that it believes that allowing the use of oxygenates in the compliance formula may enable some small refiners to comply with the 0.62 vol% benzene standard. The commenter also noted that since Congress required the increased use of ethanol in gasoline in EPAct, EPA should promote the use of ethanol and other oxygenates whenever possible.

<u>Letters:</u>
Countrymark Cooperative, LLP OAR-2005-0036-0471

[12] The 1.3 vol% per gallon cap on RFG benzene remains.

ExxonMobil OAR-2005-0036-0772, -1013
Flint Hills Resources, LP (FHR) OAR-2005-0036-0862
National Petrochemical Refiners Association (NPRA) OAR-2005-0036-0809

Our Response:

We are allowing ethanol added downstream of a refinery to be included in a refinery's benzene calculation for all purposes under MSAT2. The refinery would be required to meet requirements specified in the RFG and anti-dumping regulations, as applicable, regarding documentation, agreements with the oxygenate blender, etc. We believe that adding ethanol and complying with other fuel requirements, e.g., the Energy Policy Act and related regulations, are part of the refinery's business as usual and are reasonable to permit as a part of this program.

4.2.5 Pre-emption

What Commenters Said:

One commenter stated that this rulemaking as proposed would remove the option of independent state regulation of gasoline benzene content from the state's list of potential tools for addressing air quality. The commenter stated that it believes that an option for state regulation should be preserved.

Other commenters noted that no state or political subdivision, other than California, may adopt a benzene content, exhaust toxics, or total toxics standard for gasoline that is different from the federal standard without requesting a waiver. Commenters cited statements from several rules where the Agency acknowledged this fact. The commenter noted that waivers cannot be granted by EPA because state benzene and toxics standards for gasoline are not necessary to achieve a NAAQS.

Many commenters also noted that because the regulations will affect virtually all of the gasoline in the United States, and since gasoline produced in one area is often distributed to other areas, federal rules should preempt State action to avoid potentially conflicting regulations.

<u>Letters:</u>
Marathon Petroleum Company, LLC (MPC) OAR-2005-0036-1008
National Petrochemical Refiners Association (NPRA) OAR-2005-0036-0809
Wisconsin Department of Natural Resources (WDNR) OAR-2005-0036-0828

Our Response:

In the NPRM, we stated that authority for the gasoline benzene program comes from the Clean Air Act, specifically section 211(c), which includes a preemption of state fuel programs in section 211(c)(4). [71 FR 15871] We believe that we are thus required to preempt any state (except for California) from further regulating benzene in those areas. The nationwide benzene program finalized today therefore preempts all states (except California which is exempt from preemption under 211(c)) from regulating gasoline benzene content.

4.2.6 Treatment of Transmix

What Commenters Said:

One commenter stated that it supports EPA's proposal to omit transmix processors from the benzene standard because they have no control over the benzene in the transmix streams they receive and typically are too small to invest in benzene extraction or treatment equipment that may or may not be needed. This commenter believes that the benzene in the gasoline they receive as feedstock would have been accounted for at its point of production.

The commenter stated that it believes that EPA indicated that if outside blending components are added to transmix-derived gasoline, the final blend should be subject to the new standard. The commenter stated that since benzene in the transmix-derived gasoline would have been accounted for at its production point, EPA should consider requiring only the outside material added to the transmix-derived gasoline meet the new standard and not the completed blend. The commenter further stated that it believes that the product transfer document that the transmix processor receives for the blending component could indicate the benzene level of the product, thus allowing the transmix processor to blend the material in without having to invest in testing equipment that it otherwise would not need.

<u>Letters:</u>
Gladieux Trading & Marketing Co., L.P. (Gladieux)OAR-2005-0036-0972

Our Response:

We had proposed that transmix processors would be subject to the benzene standard if they add gasoline blending components to the gasoline produced from transmix (see 71 FR 15891). We agree with the comment that only the blending component added to the gasoline produced from transmix should be subject to the standard, for the reasons stated by the commenter, and we are finalizing this provision. Thus transmix processors are not subject to the benzene standard unless they add other blendstocks to the gasoline produced from transmix. If they do this, they will only be subject to the benzene requirement for the blendstock added, not for the entire blend (transmix plus blendstock). This is consistent with the treatment of transmix in other EPA gasoline programs.

4.2.7 Exemptions for U.S. Territories

What Commenters Said:

ExxonMobil commented that it believes that U.S. Pacific territories should be exempt from the MSAT2 requirements. The commenter noted that when EPA promulgated MSAT1, the Agency exempted the Pacific territories of Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands (at §80.820(d)), but the MSAT2 proposal does not appear to exempt these territories. The commenter noted that EPA has been exempting these territories from most of the fuel specification requirements imposed on the mainland U.S. since their source of gasoline supply is altogether different, and the environmental issues not as prevalent. The commenter stated that it believes that EPA should exempt these territories from the MSAT2 requirements, as was done for MSAT1, Highway and Nonroad diesel, and Tier 2 Gasoline.

<u>Letters:</u>
ExxonMobil OAR-2005-0036-0772, -1013

Our Response:

As discussed further in section VI.B.1 of the preamble to the final rule, gasoline produced for use in the American territories of Guam, the Northern Mariana Islands, and American Samoa is not subject to the gasoline benzene standards. Gasoline produced for use in these areas is currently exempt from the MSAT1 standards, and for the same reasons we discussed in the MSAT1 final rule (66 FR 17253, March 29, 2001), we are exempting gasoline produced for use in these areas from this rule.

4.3 Lead Time for Compliance

What Commenters Said:

Many commenters stated that they believe that the January 1, 2011 start date is reasonable. Some commenters, however, asked that EPA give serious consideration to earlier implementation. Some of these commenters noted that Canada implemented controls on gasoline benzene (including a per-gallon cap) 18 months after rule adoption. Some also suggested that increases in renewable fuel use could expedite compliance with the MSAT2 standards by several years. The Municipality of Anchorage urged EPA to speed the implementation of benzene limits in gasoline supplied in Alaska.

On the other hand, many other commenters stated that EPA should provide a full four years of lead time for refiners and importers to comply with the standard, as in past regulatory programs. These commenters stated that they believe that the lead time provided by the proposed rule would create difficulties and urged that, if the rule is to be finalized in February 2007, the program start date should be January 1, 2012 to allow for a full four years of lead time. A few stated that they would support a compliance date that is exactly four years after the effective date of the final rule. The four years are needed for the concept reviews, design, engineering, permitting and construction of refinery facilities necessary for compliance. They believe that an effective date any earlier than this would put undue time pressure on the industry and would not allow sufficient time for optimally developing and integrating the changes required to meet the benzene standard. Some of these commenters pointed to other overlapping regulatory programs as a reason to extend the leadtime.

Letters:
American Petroleum Institute (API) OAR-2005-0036-0366, 0367
(Municipality of) Anchorage Department of Health and Human Services Anchorage OAR-2005-0036-0976
BP OAR-2005-0036-0824, 0837
Environmental Defense, NRDC, U.S. PIRG, ALA OAR-2005-0036-0868
ExxonMobil Refining & Supply Company OAR-2005-0036-0772
Independent Fuel Terminal Operators Association (IFTOA) OAR-2005-0036-1007
Marathon Petroleum Company LLC OAR-2005-0036-1008
National Petrochemical Refiners Association (NPRA) OAR-2005-0036-0809
New Jersey Department of Environmental Protection, Division of Air Quality (NJ DEP) OAR-2005-0036-0829
New York State Department of Environmental Conservation (NYDEC) OAR-2005-0036-0722
NESCAUM OAR-2005-0036-0993
STAPPA/ALAPCO OAR-2005-0036-0836

Our Response:

Section 202(l)(2) requires that we consider lead time in adopting any fuel control for MSATs. We proposed that refiners and importers meet the 0.62 vol% average benzene standard beginning January 1, 2011 (January 1, 2015 for small refiners). This date was based on the industry experience that most of the technological approaches that we believe refiners will apply – rerouting of benzene precursors around the reformer and use of an existing isomerization unit – will take less than two years. The more capital intensive approaches – saturation and extraction – generally take two to three years to complete. The January 1, 2011 date provides nearly four years of lead time. We believe this is an appropriate amount of lead time, even taking into account that other fuel control programs (notably the Nonroad Diesel program) will be implemented in the same time frame.

Some commenters supported earlier start dates, referring in some cases to the experience of Canada in regulating gasoline benzene. However, these comments failed to acknowledge the less stringent Canadian standard (0.95 vol%) which naturally takes less lead time to implement. No commenter provided information that challenged our assessments of the technical lead time for the range of benzene control approaches that will be implemented. Given that the technologies that need to be used to comply with this standard all require less time than the lead time available, we continue to believe that a January 1, 2011 start date is appropriate. Furthermore, an important aspect of the design of this program as proposed is the recognition that not all of the benzene reduction would occur at once. As discussed in detail in section VI.A.2.b of the preamble, we expect that individual refiners will use the ABT program to schedule their benzene control expenditures in the most efficient way, using the early credit and standard credit provisions. This will essentially create a gradual phasing-in of the reductions in gasoline benzene content, beginning well before the initial compliance date of January 1, 2011 and spreading out industry-wide compliance activities over several years. Therefore, we are finalizing a start date of January 1, 2011 for the average standard, as proposed.

4.4 Costs

4.4.1 General

What Commenters Said:

The American Petroleum Institute (API) commented that it believes that EPA underestimated capital and total costs of the proposed gasoline benzene standard. The commenter noted that EPA estimates a total capital cost for its proposed 0.62 vol% standard with ABT program to be $500 million (in 2003 dollars). API commented, however, that it believes that the capital costs will be considerably higher - by a factor of 3 – and it pointed to an estimate made by Baker and O'Brien's of $1, 476 million (in 2006 dollars) [page 43]. A refiner asserted that capital costs would be 2 – 3 times greater than EPA's estimates based on their experience installing benzene control technology. Another refiner said that its own capital cost estimate for complying with the proposed benzene control standard could reach $250 million for its refineries which comprise about 6% of the U.S. gasoline pool, which suggests that the EPA capital cost estimate was understated by a factor of 3 - 4.

API further commented that in the EPA-estimated costs (capital and operating) for a 0.62 volume percent benzene average proposed standard, no compliance margin was assumed, nor was the degree of likely ABT program market efficiencies assessed. The commenter stated that it believes that this alone could lead to an understatement of the proposed program costs and impacts. The commenter noted that the API Baker and O'Brien report has incorporated provisions for these aspects by modeling at 0.60 volume percent and assuming a 10 volume percent unused credit balance for compliance margins and market place trading efficiencies.

API further commented that the analogous Baker and O'Brien cost curve (see first figure on page 46 of the Baker and O'Brien report) also suggests that a portion of the gasoline pool can meet the 0.62 volume percent benzene target at little or no cost, but significantly less than 50 volume percent of the pool. The commenter also stated that the Baker and O'Brien curve indicates tail end costs (i.e., costs to refineries at the tail end of the cost distribution curve) in the range of 4 to 7 cents per gallon. Other reasons cited include EPA's underestimating of benzene control costs, include grossly underestimating the costs for the highest cost refiners, and that more than half of refiners would incur no cost at all.

API noted that EPA's refinery linear programming cost LP modeling used 2000 as the base year, and only 4.3 billion gallons of ethanol were assumed in 2010. The commenter stated that it believes that these two key variables may impact the quality of the assessment made by EPA. API further commented that the natural gas and crude oil prices that were taken from the EIA/AEO 2005 (e.g., as stated on page 922 of Chapter 9 of the RIA), crude oil prices were assumed to be $27 per barrel for the EPA study.

One commenter stated that it believes that EPA's estimate of the additional cost of the new benzene standard of an average of 0.13 cents per gallon has been underestimated. It estimates that its after-tax costs will be as high as 0.30 cents per gallon.

<u>Letters:</u>
American Petroleum Institute (API) OAR-2005-0036-0366, 0367
ExxonMobil OAR-2005-0036-0772, -1013
Marathon Petroleum Company, LLC (MPC) OAR-2005-0036-1008

Our Response:

Several commenters stated that our capital and overall cost estimates are too low, submitting their own cost study as support. In Section 9.7 of Chapter 9 of the final RIA, we summarize the methodology and final costs of the oil industry's cost study of the proposed gasoline benzene program. That section of the final RIA compares the methodology and cost results of the industry cost analysis to our final rule cost analysis, highlighting the differences between our two studies and our basis for projecting lower costs than are projected in the industry study.

The cost analysis conducted by API estimated an aggregate capital cost of 1,476 million dollars while in the proposed rulemaking we reported that the refining industry would need to invest 500 million dollars in new capital costs. In the draft RIA for the proposed rule, we acknowledged that our capital cost estimates did not include any capital costs for octane recovery and additional hydrogen production, although we committed to estimate them and include them as part of our final rule cost estimates.

For our final rule cost analysis, we reviewed our capital cost estimates that serve as inputs for our refinery modeling analysis. In many cases we updated our capital cost estimates to reflect the most recent data available, capturing the recent run-up in capital costs that has occurred as capital costs have increased faster than inflation. We also estimated the capital costs associated with octane recovery and additional hydrogen demand that is estimated to occur due to the application of the benzene control technologies. Our capital cost estimate for our final rule benzene program is 1,100 million dollars.

Our new capital cost estimate is still lower than API's capital cost estimate and we identified four reasons why. First, API modeled a more stringent benzene annual average standard than required in our final benzene standard. API modeled the cost for a 0.60 vol% average benzene standard as opposed to our final rule benzene program which requires that refiners comply with a 0.62 vol% annual average benzene standard. The more stringent average benzene standard modeled by API would require that some refiners invest in a more expensive benzene control technology, thus raising the estimated capital cost. This difference between our two studies is offsite slightly by our adoption of a 1.3 vol% maximum average benzene standard. However, as indicated by our cost comparison summarized in Chapter 9 of the RIA, the maximum average standard adds much less to the cost than the more stringent average benzene standard.

The second reason the oil industry's cost study estimates higher capital costs is an assumption that refiners would hold on to a substantial amount of credits, and therefore overcomply significantly with the 0.62 vol% average standard. As a result of this assumption, the average benzene level estimated by their cost study was 0.56 vol% benzene (which is much lower than the average benzene standard that they modeled), resulting in higher capital costs. The ABT and other provisions provided by the benzene program is expected to reduce the need for refiners to store up extra credits; as a result we believe refiners are likely to target complying with the 0.62 vol% average benzene standard instead of significantly lower benzene levels. Thus, any deeper benzene reductions would be unnecessary.

The third reason why the oil industry cost analysis estimated higher capital costs is that it assumed that when a refiner put in a benzene extraction unit, it would install a unit which would also extract xylene and toluene (called BTX extraction), which significantly increases the capital costs associated with extraction. We considered making a similar assumption when we began our process for estimating the costs for benzene control, but a vendor of benzene extraction technology advised against such an assumption. The vendor said that most refiners would only put into place the necessary capital for benzene extraction because so much new xylene extraction capacity is being installed overseas, and toluene is a less desirable aromatic compound. In any case, if a refiner were to elect to extract aromatic compounds other than benzene, it would not be a cost of this rule, but would instead be based on a refiner's desire to begin participating, or to further participate, in those markets.

The fourth reason for the oil industry's higher capital cost estimates is that the study used very high offsite factors[13] and also added a contingency factor for their capital

[13] Onsite costs are for the primary unit including the distillation column, heat exchangers, pumps, heaters, piping, valves and instrumentation. Offsite costs are for administration and control buildings, cooling tower, electrical substation and switchgear, water and waste treatment facilities, feedstock and product storage and loading and offloading, spare equipment kept onsite and catalysts. Normally refiners estimate offsite costs for each project which can vary from zero to a factor several times greater than the onsite costs. For national fuel control programs, cost estimation is averaged and a factor is used to indicate the fraction that offsite costs comprise of onsite costs. This factor is applied for all the technologies requiring capital investment and is expressed as a single onsite and offsite capital cost estimate.

costs. Based on actual offsite cost information from an engineering and construction company, offsite costs range from 10 to 80 percent of the onsite costs,[14] yet API consistently assumed an offsite factor at the highest end of this range. In addition to their capital cost estimate, their analysis adds a 15 percent contingency cost factor. However, contingency cost factors are usually reserved for cost estimates with a high degree of uncertainty. Because the capital costs associated with these benzene control technologies are so well known, it is inappropriate to tack on a contingency cost factor here.. Thus, we believe that the use of high offsite factors and contingency factors overestimates capital costs.

Our higher capital costs contributed to increasing our per-gallon costs, but our per-gallon costs also increased for other reasons. For our final rule cost analysis, we assumed a higher crude oil price of $47 per barrel instead of the $27 per barrel crude oil price used for the proposed rule. The projected natural gas prices are also higher for the final rule cost analysis compared to those used for the proposed rule cost analysis. One commenter stated that our LP modeling used 2000 as the base year, and only 4.3 billion gallons of ethanol were assumed in 2010. The commenter stated that it believes that these two key variables may impact the quality of our cost assessment. For our final rule analysis, we estimated costs based on 9.6 billion gallons of ethanol entering the gasoline pool. Unlike the oil industry cost analysis, our octane costs take into account this large volume of ethanol in the gasoline pool. Our LP refinery model still uses the year 2000 as the base year. However, the LP refinery cost model was primarily used to generate octane recovery and hydrogen supply costs. Our refinery-by-refinery cost model, which is the prime tool used for estimating the costs of our program, was updated for our final rule analysis to be calibrated against year 2004 gasoline volumes and gasoline benzene levels.

All these changes, along with others, resulted in our per-gallon benzene control costs increasing by about a factor of two compared to the benzene control costs estimated for the proposed rule.[15] Consistent with the comments, the highest modeled costs of compliance in each PADD for our final rule cost analysis, which now includes a 1.3 vol% maximum average standard, were also in the 4 to 6 cents per gallon range, although we discussed a benzene control strategy which we did not model that would mean much lower benzene control costs in practice (see section 9.6.1 of Chapter 9 of the RIA). In addition, we conservatively estimated costs for reformate extraction although refineries may extract benzene without regard for the rule's requirements due to rising benzene demand by the petrochemical industry. Thus, both our cost studies may tend to overestimate compliance costs for some refineries.

Commenters from the oil industry also stated that our proposed cost analysis estimated too high a percentage of refineries that could comply with the benzene program

[14] Rees, Conway, Senior Process Director, Fluor; Technical Session: Considerations when Revamping for ULSD, Hydroprocessing Principles and Practices, National Petrochemical and Refiners Association Question and Answer Forum, October 2006.

[15] About 20 percent, or 0.03 cents per gallon, of the higher cost we are reporting for the final rule is attributed to the addition of the 1.3 vol% maximum average benzene standard.

at no cost. Our final rule cost analysis shows that less than 40 percent of the oil industry can comply with no or less than zero cost, which seems consistent with the API cost study.

One commenter stated that it believes that EPA's estimate of the additional cost of the annual average benzene standard of an average of 0.13 cents per gallon has been underestimated because it estimates that its after-tax costs will be as high as 0.30 cents per gallon. We presented the before-tax per-gallon costs averaged over only the refineries which are projected to take steps to reduce their benzene levels, which is 0.40 cents per gallon. This 0.40 cents per gallon cost is higher than that estimated by the commenter, and if we had expressed the costs on an after-tax basis, our costs would be higher still. However, no conclusion can be reached by this comparison since our average per-gallon cost is determined by the average costs for many diverse refineries and we do not know what benzene control technologies that the commenter assumed for its comments.

4.4.2 Reporting of Costs

What Commenters Said:

The Alaska Department of Environmental Conservation (ADEC) commented that it would appreciate any more specific information from EPA about cost impacts expected from this rule.

Letters:
Alaska Department of Environmental Conservation (ADEC) OAR-2005-0036-0975

The commenter stated that it would appreciate any more specific information from EPA about cost impacts expected from this rule. In Chapter 9 of the preamble and in Chapter 9 of the draft RIA for the proposed rule, detailed benzene control cost estimates were provided for the proposed fully phased-in benzene program as well as other benzene programs considered. Also the cost input information was provided in Chapter 9 of the draft RIA for specific benzene control technologies. The cost impact to refiners and consumers was estimated by the Economic Impact Analysis (EIA) as summarized in Chapter IX of the preamble and Chapter 13 of the RIA.

For the final rulemaking, updated, detailed cost estimates are provided for the final benzene program in Chapter 9 of the preamble and Chapter 9 of the final RIA. The cost estimates were updated from those in the proposed rule to reflect more recent capital cost information, more recent projections for utility prices, crude oil prices, benzene prices and to model the final benzene program which includes a 1.3 maximum average standard. The EIA estimates the costs to refiners and consumers in Chapters IX of the preamble and Chapter 13 of the RIA.

4.5 Refinery Modeling

What Commenters Said:

The commenter noted that proposed rule is entirely dependent on modeled predictions to achieve its reduction goals, with a broad, flexible ABT program and a minimal program for monitoring and enforcing compliance. The commenter stated that it believes that, if refiners do not act as the model predicts or if conditions change, the benzene reductions may not occur in the manner and to the degree predicted by the model.

API also commented that it believes that EPA presumed a large number of facilities will install benzene extraction units or revamp their existing extraction units. While this is a low cost approach, the commenter noted, it keys on an overoptimistic presumption that there will be full utilization and need of the extracted components in the world market. API commented that it believes that greater utilization of benzene saturation and isomerization strategies will be taken to preserve supplies.

Lastly, the commenter stated that it believes that EPA failed to recognize that the public cost of environmental programs is not the average cost across the entire industry but the incremental cost that must be paid to acquire the final increment of gasoline supply; the commenter further noted that even using EPA's low cost estimates, this incremental cost is 10 times the average cost projected by the Agency modeling.

Letters:
American Lung Association (ALA) OAR-2005-0036-0365 (hearing comments)
American Petroleum Institute (API) OAR-2005-0036-0366, 0367
Marathon Petroleum Company, LLC (MPC) OAR-2005-0036-1008

Our Response:

One commenter stated that it believes that EPA presumed a large number of facilities will install benzene extraction units or will revamp their existing extraction units. While this is a low cost approach, the commenter noted, it keys on an overoptimistic presumption that there will be full utilization and need of the extracted components in the world market. The commenter went on to say that it believes that greater utilization of benzene saturation and isomerization strategies will be taken to preserve gasoline supplies. Our final rule analysis projects a lower reliance on benzene extraction than the proposed rule analysis. However this change in the expected use of benzene extraction is more due to the higher extraction capital costs estimated for the final rule analysis compared to the proposed rule analysis than any issues associated with benzene supply. Also, as we pointed out in the energy and supply discussion of the RIA and in section 4.8 of this response to comment document, the sale of the volume of benzene into the petrochemical market, which likely will phase in over time because of the ABT program, may occur independently of this rule's requirements based on the projected increased benzene demand from the petrochemical sector over this same time period. Moreover, as further explained in that response, even if the amount of benzene extraction occurring in this time frame is more than the petrochemical market can absorb, rather than there being a large decrease in benzene price due to oversupply, we would expect that the marginal cost benzene producers would reduce their benzene production. These marginal cost benzene producers are those which convert toluene into benzene. They would be expected to reduce benzene production and return the toluene back to the gasoline pool. This toluene reentering the gasoline pool would make up for a part, or even all, of the volume and octane of the newly extracted benzene. Thus, under either of these scenarios, we expect only a very small or perhaps no impact on supply by increased benzene extraction due to this benzene program.

One commenter stated that it believes that EPA failed to recognize that the public cost of environmental programs is not the average cost across the entire industry but the incremental cost that must be paid to acquire the final increment of gasoline supply. The commenter further noted that even using EPA's low cost estimates, this incremental cost is 10 times the average cost projected by the Agency modeling. We disagree with the assertion that the cost of our environmental programs is the marginal cost of meeting the benzene control program, which essentially reflects the cost of the most expensive refinery to comply. Often, the price of gasoline is estimated to increase based on the marginal cost of the highest cost producer. However, using this sort of analysis to estimate social costs would be incorrect because it would reflect a certain amount of transfer payment from the consumer to the oil industry. We estimate societal costs of our rulemakings by the cost of installing and operating benzene control technologies across the industry, not the last increment of control.

4.6 Refinery-Specific Impacts

What Commenters Said:

Flint Hills Resources noted that it operates refineries that do not have ready access to chemical markets, which it believes essentially eliminates the choice of a benzene extraction strategy that could provide an acceptable return on capital invested.

Sinclair Oil Corporation, Flying J. Inc., Suncor Energy (U.S.A.) Inc., and Tesoro Corporation commented that the cost model in Table IX.A-2 projects PADD 4 and 5 refineries investing in control technology only to reach an average benzene level of about 1.0 volume percent, not the proposed 0.62 volume percent standard. The commenters further stated that model assumes western refineries would enter 2011 out-of-compliance with the new standard and rely on benzene credits to make up the difference. The commenters stated that they believe that the model does not factor in a price for these credits in the cost estimate. Thus, the commenters believe that the compliance cost estimates for PADDs 4 and 5 are greatly understated. Lastly, the commenters noted that they believe that the model's assumption of western refineries using benzene credits to achieve the 0.62 standard is premised on large uncertainties; namely, that benzene credits would be widely available at a price more affordable than compliance. (*See p.3 of Docket Number 0989 for table*.)

United Refining Company (United) commented that while any reduction in benzene is onerous, United would face significant technical difficulties and costs in meeting a benzene standard less than one percent by volume because, at a minimum, a new unit would be required to convert naturally occurring benzene and benzene produced by the fluid catalytic cracking (FCC) unit into cyclohexane (or other chemicals) with no corresponding economic benefits.

United noted that its benzene is currently averaging 1.50 percent in regular and 3.25 percent in premium gasoline. The commenter further noted that a major source of benzene at its refinery is reformate followed by gasoline produced at the FCC unit. The commenter noted two strategies that it could use for benzene reduction: 1) minimize benzene precursors going to the reformer, and 2) eliminate the benzene after it is formed. The commenter stated that it believes that to reduce benzene in the entire gasoline pool to levels below one percent, it would likely be forced to implement both strategies. Further, the commenter stated, in addition to capital costs, the new unit and existing unit modifications will increase operating costs and affect other properties of the gasoline pool. The commenter gave the example that it would reduce the amount of hydrogen available from the reformer unit, and this hydrogen is required to hydrotreat diesel fuel and gasoline to comply with the various low sulfur fuel restrictions, and it would substantially decrease the octane number in the gasoline currently produced.

Silver Eagle Refining commented that it operates two small "niche" refineries, and that the majority of its gasoline is produced by catalytic reforming and thus the benzene content of its finished gasoline ranges from 2.5 to 4.6 percent. The commenter stated that it does not endorse EPA's proposed gasoline benzene standard of 0.62 percent for technical and economic reasons. Technically, the commenter stated, a unit capable of saturating and converting benzene into other products (such as cyclohexane) may not provide enough reduction of benzene to meet EPA's proposed standard. The commenter also stated that converting benzene into cyclohexane will likely reduce the octane of its gasoline pool. Lastly, the commenter stated that replacement of the lost octane will be difficult due to the small "niche" configuration of its two refineries.

MPC stated that refineries may not implement benzene content reduction strategies as the proposed rule predicted, and that it does not have confidence that the Agency has made correct compliance cost estimates for every refinery. The commenter stated that it believes that the MSAT2 program places a very large burden on the credit trading program, and it believes that it is unreasonable to assume that every refiner seeking benzene content credits will always find affordable credits.

<u>Letters:</u>
Flint Hills Resources, LP (FHR) OAR-2005-0036-0862
Marathon Petroleum Company, LLC (MPC) OAR-2005-0036-1008

Sinclair Oil Corporation, Flying J. Inc., Suncor Energy (U.S.A.) Inc., and Tesoro Corporation OAR-2005-0036-0989
Silver Eagle Refining, Inc. OAR-2005-0036-0839
United Refining Company OAR-2005-0036-0827

Our Response:

One commenter expressed concerned that benzene extraction is not available to them because they are not on the Gulf Coast, nor are they on the East Coast, and this takes away a means to reduce their benzene levels that provides a return on investment. We conservatively estimated that refiners who are not located near to the benzene petrochemical markets would use other means to comply with the benzene program besides benzene extraction. However, refiners outside the Gulf and East Coasts may find it economical to transport a benzene rich stream to these regions for extraction. The feasibility and estimated cost of benzene control is based on the use of four different benzene control technologies that reduce benzene levels in the reformer or which reduce the benzene levels of reformate, the product stream of the reformer. While this does include extraction, our cost analysis projects that many refineries will use benzene control strategies other than extraction. Thus, the estimated cost of this benzene program, which was found to be reasonable, is based on refineries using a mix of benzene control technologies.

Another commenter stated that they may have to reduce the benzene levels of the naphtha produced by the fluidized catalytic cracker to reduce the benzene level of its gasoline below 1.0 vol%. Our feasibility and cost analysis shows that all refineries could comply with the 1.3 vol% benzene maximum average standard by using benzene saturation, although many may be able to achieve the maximum average standard at a lower cost using other lower cost reformer-based benzene control technologies. Once below the maximum average standard, the refinery can use credits to comply with the 0.62 vol% average benzene standard. If the refiner did not want to rely on credits to comply with the 0.62 average benzene standard, it could further control benzene from its reformer by applying benzene extraction or saturation. Our feasibility analysis projects that only eight refineries would not be able to achieve the 0.62 vol% average standard even after applying saturation or extraction to their reformate stream. These eight refineries would be able to reduce their gasoline benzene levels below the average standard by reducing the benzene levels in other benzene-containing gasoline blendstocks through distillation that would channel the benzene into their reformate benzene treating unit. Based on some estimates of benzene control costs for these other benzene containing gasoline blendstocks (see section 6.4.2 of Chapter 6 of the RIA), we believe that the costs would be acceptable for refiners to reduce the benzene levels of these other gasoline blendstocks.

Several commenters expressed concern that credits may not be available. Due to the range in benzene control costs among refiners, and the extensive flexibility in the program to generate trade and use credits, we have every reason to believe that refiners will freely use the ABT program to realize its cost savings. This means that credits will be widely available. Furthermore, we committed ourselves to review the ability of the credit market to provide credits just after the program begins in 2011 and we will be monitoring the early credit market through the pre-compliance reports. If the economic conditions are somehow different over the next several years than that estimated for our refinery cost study (i.e., higher crude oil costs) as one commenter suggested, the ABT program will allow refiners to alter their benzene control choices to comply with the benzene program at the lowest cost. The benzene program is designed so that the refining industry will achieve 0.62 vol% benzene on average at lowest cost regardless of how feedstock prices, product prices or other conditions affecting refiners may change. (The final rule also includes a hardship provision specific to small refiners, providing potential relief upon a showing that the refiner could only meet the annual average standard through purchase of credits, but that credits are unavailable for practical or economic reasons.)

One commenter said that our cost analysis could be underestimating costs if refiners end up generating or using credits less freely. We recognize that this is an uncertainty in our cost modeling. Conversely, our cost analysis may be overstating costs if some refineries, particularly large refineries, are able and choose to reduce the benzene levels of other gasoline blendstocks, such as light straight run naphtha, light hydrocrackate, and light coker naphtha, and by doing so generate more credits which can be traded to other refineries which find it more cost-effective to purchase credits rather than to reduce the gasoline benzene levels of its own refineries. Thus, our cost analysis inherently contains some uncertainty with potentially higher or lower costs, and potentially higher and lower regional benzene levels, than that which we have estimated. It would be difficult to conduct any uncertainty analysis because of the very large number of potential uncertainties that could affect the cost of compliance.

Several commenters stated that the costs for benzene control are likely to be high for them and that EPA likely underestimated their costs because it did not factor in the purchasing price for credits. Our cost analysis estimates the nationwide costs to comply with the benzene program based on the projected actions taken by individual refiners to bring the nation into compliance. The ABT program allows for benzene reductions that can be achieved more cost-effectively by some refiners who choose to overcomply with the average benzene standard to be transferred to other parties through the sale of credits. Those refiners who would find it more costly to achieve the same benzene reductions can save in their compliance costs by purchasing those credits. Thus there will be a significant cost savings to the nation. Our cost analysis does not attempt to determine what the costs will be for each individual company after credit trading, and even if we had it would not be appropriate to report such results. While we did not estimate the price of a credit due to the uncertainties involved, because the credits will be generated principally by refiners with low costs for reducing their benzene levels, it is likely that the price of a credit will be much lower than the benzene reduction costs for the refineries faced with high benzene control costs and who will be the most interested in purchasing credits.

A couple commenters stated that reducing benzene will reduce their hydrogen supply and reduce the octane of their gasoline pool. When we modeled the application of the various benzene control strategies across the industry to achieve the reductions in gasoline benzene content to estimate costs, we also modeled the cost of making up reductions in both octane and hydrogen supply (see section 9.1.4.1 of Chapter 9 of the RIA). Individual refiners will bear different costs. However, despite the added cost for making up lost octane and hydrogen or making additional hydrogen available for saturating benzene, the costs incurred were considered to be reasonable (see section A.1 of Chapter VI of the preamble).

4.7 Averaging, Banking, and Trading (ABT) Program

We proposed a nationwide averaging, banking, and trading (ABT) program that would allow refineries and importers to use benzene credits generated or obtained to meet the 0.62 vol% annual average benzene standard in 2011 and beyond (2015 and beyond for small refiners). We are finalizing a very similar program with the addition of a 1.3 vol% maximum average standard that becomes effective July 1, 2012 (July 1, 2016 for small refiners). The 1.3 vol% standard must be met based on actual refinery benzene levels, essentially placing a "ceiling" on credit use. While the 1.3 vol% maximum average standard imposes a limitation on credit use, we believe that the ABT program we are finalizing still offers much of the intended compliance flexibility, and accordingly, that the comments presented below are still relevant.

4.7.1 Early Credit Generation

4.7.1.1 Trigger Point

We proposed a ten percent (10%) reduction trigger point for early credits to ensure that changes in gasoline benzene levels result from real refinery process improvements (71 FR 15875).

What Commenters Said:

We received comments supporting the proposed 10% reduction trigger point as an appropriate mechanism for guarding against "windfall" early credit generation..

We also received comment that the early credit trigger point should not apply to refiners whose early credit baseline is at or below the 0.62 vol% standard. The commenter argued that this restriction penalizes companies who have provided the health benefits of low-content benzene to the communities they serve in advance of this rule. They believe it will be difficult for refiners who currently meet the standard to significantly reduce benzene levels further and that they should be allowed to generate early credits if their average benzene levels are below baseline levels without the trigger point restriction.

Letters:
American Lung Association OAR-2005-0036-0868, OAR-2005-0036-0365
Flint Hills Resources OAR-2005-0036-0862

Our Response:

As described in more detail in the preamble to the proposed rule (71 FR 15875), we believe that a 10% reduction trigger point is appropriate and necessary to prevent windfall early credit generation. We disagree that refineries already at or below 0.62 vol% benzene should be excluded from having to meet the early credit trigger point for this very reason. We acknowledge that it could be more difficult for refineries with already low benzene levels to make additional reductions. However, refineries with gasoline benzene levels at or below 0.62 vol% do not have as much need for early credits (compared to refineries above the standard) since they are less likely to need additional lead time to comply with the standard.

4.7.1.2 Imported Gasoline

We proposed that importers would not be permitted to generate early credits for several reasons described in more detail in the proposal (71 FR 15874).

What Commenters Said:

The Independent Fuel Terminal Operators Association (IFTOA) objected to the EPA's rationale for excluding importers. IFTOA commented that because importers have to meet the same benzene standard as refiners, they should be entitled to earn the same early credits if their imports result in a net reduction in benzene emissions. They pointed out that the importer is competing with the domestic refiner who will have the advantage of including credits in his pricing and that the benzene rule should not place importers at a competitive disadvantage. They also noted that importers do not simply redistribute reduced-benzene product from one importer to another to obtain an unwarranted benefit. According to IFTOA, importers understand the value of the product, particularly when credits may be generated, and price their cargo accordingly. The commenter stated that the economic incentive to move imports from one baseline to another is offset by the premiums paid. Finally, IFTOA pointed out that the ultra-low sulfur diesel program allows both refiners and importers to generate early credits. They believe that the early credit provision of the diesel sulfur program is a valid precedent for the gasoline benzene program, and that EPA should encourage importers to obtain cleaner gasoline as soon as possible.

Letters:
Independent Fuel Terminal Operators Association (IFTOA) OAR-2005-0036-1007

Our Response:

While raising important issues and concerns, the commenters failed to address the Agency's overarching rationale behind excluding importers from generating early credits under the ABT program. Given the fluid nature of many importer operations, it would be difficult to verify that a "net reduction in benzene emissions" actually occurred in exchange for early benzene credits.

First, it would be difficult to set a "baseline" or reference point from which to measure early benzene reductions. Although an importer may have imported gasoline into the U.S. during the 2004-2005 baseline period, the average benzene content of the imported gasoline may not necessarily be representative of their usual cargo.

Likewise, a reduction in an importer's average gasoline benzene content may not necessarily be representative of a benzene reduction made at the foreign refinery level. Because of their variable operations, importers could potentially redistribute the importation of foreign gasoline to generate early credits without the overall pool of imported gasoline becoming incrementally cleaner. For example, say from January 1, 2004 to December 31, 2005 Importer A brought gasoline into the U.S. with an average benzene content of 1.50 vol%. During the same time period, Importer B imported gasoline that contained 1.00 vol% benzene on average. Beginning in June 2007, Importer B could begin transferring/selling its 1.00 vol% gasoline to Importer A for importation into the U.S. Consequently, Importer A could generate early credits based on the difference in benzene content (1.50 – 1.00 = 0.50 vol%) divided by 100 and multiplied by the volume of the imports (credits expressed in gallons of benzene). This would result in "windfall" early credits being generated with no net benzene emission reduction value. While the same gaming potential theoretically exists among refiners (although it would be low given our knowledge of the refining industry and our prohibition against refiners generating early credits for simply transferring gasoline/blendstocks from one refinery to another), we believe that the importer potential is much greater based on their ability to select which cargos they import into the U.S., their respective volumes, etc.

Finally, we only allowed importers to participate in the ULSD early credit program because it was a fundamentally different program than the one adopted in this rule. There was not an issue with establishing accurate sulfur baselines and/or verifying sulfur reductions because early credit generation was simply based off of producing/importing 15 ppm diesel fuel earlier than required. Since early credit generation was not tied to individual refinery/importer sulfur levels or reductions but rather to making compliant diesel fuel available sooner, importers and refineries alike could participate in the early credit program.

In addition to the reasons mentioned above, importers do not have the same need for early credits since they are not responsible for making investments in benzene control technology and thus will not need additional lead time to comply with the standard. Accordingly, we are finalizing the proposed early credit program which continues to exclude importers from participating. However, foreign refiners with individual refinery baselines established under § 80.910(d) who imported gasoline into the U.S. in 2004-2005 are eligible to generate early credits.

4.7.1.3 Blendstock Trading

In the proposal, we prohibited refiners from moving gasoline and gasoline blendstock streams from one refinery to another in order to generate early credits because this type of transaction would result in artificial credits with no associated emission reduction value. If traded and used towards compliance, these artificial credits could negatively impact the benefits of the program. We considered basing credit generation for multi-refinery refiners on corporate benzene baselines instead of individual refinery baselines, but determined that this could hinder credit generation. If a valid reduction was made at one refinery and an unrelated expansion occurred at another facility during this time, the credits earned based on a corporate baseline could be reduced to zero. As a result, we proposed to validate early credits based on existing reporting requirements (e.g., batch reports and pre-compliance reporting data) and sought comment on our approach (71 FR 15875).

What Commenters Said:

We received comments that refiners typically trade blending components between refiners to maximize production while minimizing cost. Further, that any discouragement to these normal transactions could hinder efficient optimum gasoline production. The commenters concluded that such companies should not be prohibited from generating early credits.

<u>Letters:</u>
Caribbean Petroleum Corporation OAR-2005-0036-1010
Colonial Oil Industries OAR-2005-0036-0990
U.S. Oil & Refining Co. OAR-2005-0036-0992

Our Response:

We recognize that many refiners trade blending components between refineries to maximize gasoline production while minimizing cost. As a result, we are not prohibiting these types of normal refinery activities, nor are we prohibiting such refineries from participating in the early credit program. We are simply requiring that, in order to be eligible to generate early credits, refineries make real operational changes and/or improvements in benzene control technology to reduce gasoline benzene levels. In most cases, moving gasoline blendstocks from one refinery to another does not result in a net benzene reduction (one refinery gets “cleaner” at the expense of another getting “dirtier”). Accordingly, refineries that lower their benzene levels exclusively through blendstock trading (no additional qualifying reductions) are not eligible to generate early credits under the ABT program. An exception exists for refineries that transfer benzene-rich reformate streams for processing at other refineries with qualifying post-treatment capabilities, e.g., extraction or benzene saturation units. Under this scenario, the transferring refinery would be eligible to generate early credits because a real operational change to reduce gasoline benzene levels has been made. The regulations at § 80.1275 have been modified to more clearly reflect our intended early credit eligibility provisions, and specifically address blendstock trading.

4.7.1.4 Limiting Credit Generation to Refineries Processing Crude Oil

In § 80.1270(a)(2), we proposed that early credits could be generated only by refiners that "produce gasoline by processing crude oil through refinery processing units." The intent was to limit early credit generation to those entities that would typically have to make refinery processing changes to reduce benzene levels and meet 10% early credit trigger point.

What Commenters Said:

We received several comments that the provision at § 80.1270(a)(2) limits early credit generation and should be clarified to include refiners who process "intermediate feedstocks" as well as crude oil through refinery processing units.

<u>Letters:</u>
Hess Corporation OAR-2005-0036-0769
National Petrochemical & Refiners Association (NPRA) OAR-2005-0036-0809
Exxon Mobil OAR-2005-0036-0772, OAR-2005-0036-1013
Marathon Petroleum Company, LLC. OAR-2005-0036-1008

Our Response:

We agree that refineries producing gasoline from intermediate feedstocks would also have to make process improvements to reduce gasoline benzene levels. Furthermore, we agree that such refineries should be eligible to generate credits for making early gasoline benzene reductions. As a result, the early credit provision at § 80.1270(a)(2) has been modified to include refineries which process intermediate feedstocks through refinery processing units.

4.7.2 Standard Credit Generation

We proposed that standard benzene credits could be generated by any refinery or importer that overcomplies with the 0.62 vol% gasoline benzene standard on an annual average basis in 2011 and beyond (71 FR 15872).

What Commenters Said:

Several commenters stated that the proposed ABT program is an appropriate phase-in mechanism for the benzene standard but that the credit trading program should not continue indefinitely. The commenters' main concern was that without a sunset date, areas with elevated benzene levels would never see real reductions because refineries in those areas would rely on credits indefinitely.

<u>Letters:</u>
Northeast States for Coordinated Air Use Management (NESCAUM) OAR-2005-0036-0993, -0369
Alaska Department of Environmental Conservation (ADEC) OAR-2005-0036-0975
Oregon Department of Environmental Quality (ODEC) OAR-2005-0036-0987

Our Response:

We are finalizing the standard credit program as proposed. As highlighted in Preamble Section VI, the ABT program was an integral component in setting the benzene standard. Without the ABT program (namely the ongoing standard credit program), the 0.62 vol% standard would not be feasible considering cost and other factors. Further, we believe that the 1.3 vol% maximum average standard we are finalizing alleviates any concerns related to prolonged elevated benzene levels as a result of the ABT program (and is a more direct means of addressing those concerns than truncating the flexibilities and efficiencies associated with the ABT program).

4.7.3 Early Credit Life

We proposed that early credits must be used towards compliance within three years of the start of the program; otherwise they would expire and become invalid. In addition, we proposed that early credits generated by and/or traded to small refiners would have an additional two years of credit life (71 FR 15837).

What Commenters Said:

One commenter suggested that EPA should lengthen the early credit use period to four years to encourage the generation of early credits. Another commenter recommended a six-year early credit life and suggested that EPA discount the value of early credits after the first three compliance years (i.e., 0.75 * value of remaining early credits in year 4, 0.5 * value of remaining unused early credits in year 5, 0.25 * value of remaining unused early credits in year 6, and early credits could not be used after compliance year 6). The commenter believes that such a discounting schedule would provide further incentives to use early MSAT2 credits in the first three compliance years or to trade them before their value declines.

<u>Letters:</u>
Marathon Petroleum Company, LLC. OAR-2005-0036-1008
National Petrochemical & Refiners Association (NPRA) OAR-2005-0036-0809

Our Response:

We are finalizing a three-year early credit life. We believe that three years is a sufficient amount of time to trade/obtain and use early credits towards compliance. The three-year early credit life we are finalizing is longer (and more flexible) than the early credit life promulgated in the gasoline sulfur rulemaking (two years). Further, we do not believe there is significant benefit to providing an even longer early credit life – beyond three years (with or without a discounting schedule). A longer credit life would simply increase the recordkeeping burden associated with this rule and prolong implementation of the 0.62 vol% standard.

In addition, we are not finalizing the two-year credit life extension proposed for early credits generated by and/or traded to small refiners. By staggering early credit usage periods (non-small refiners may use early credits from 2011-2013, small refiners may use early credits form 2015-2013), no early credits may be used towards compliance with the 2014 year. We believe that this break in early credit usage will be a valuable mechanism for funneling surplus early credits facing expiration to small refiners in need. Therefore, providing an additional credit life extension for early credits traded to small refiners is unnecessary.

4.7.4 Standard Credit Life

We proposed that standard credits must be used within five years from the year they were generated (regardless of when/if they are traded). To increase the certainty that standard credits would be available to small refiners, we proposed that standard credits generated by and/or traded to small refiners would have an additional two years of credit life (71 FR 15873).

What Commenters Said:

We received many comments supporting the proposed five-year standard credit life provision.

Letters:
Caribbean Petroleum Corporation OAR-2005-0036-1010
Colonial Oil Industries OAR-2005-0036-0990
Gladieux Trading & Marketing Co., LP OAR-2005-0036-0972
Marathon Petroleum Company, LLC. OAR-2005-0036-1008
National Petrochemical & Refiners Association (NPRA) OAR-2005-0036-0809
U.S. Oil & Refining Co. OAR-2005-0036-0992

Our Response:

Since we did not receive any adverse comments and continue to believe that a five-year standard credit life strikes a balance between program flexibility and enforceability, we are finalizing the proposed five-year standard credit-life provision.

We are also finalizing the two-year standard credit life extension for small refiners. However, we are revising the proposed provision such that, in order to be eligible for the two-year credit life extension, standard credits must be "traded to and ultimately used by" small refiners. We excluded credits generated by small refiners because refiners generating and using their own standard credits do not need additional credit life to increase the certainty that credits would be available. In addition, we added the provision that standard credits must be ultimately used by small refiners to obtain the two-year credit life extension. Credits traded to a small refiner then traded again to a non-small refiner are ineligible for the credit life extension because this would not increase the certainty that credits would be available to small refiners.

4.7.4.1 Credit Life Extension for Small Refiners

To encourage credit trading to small refiners, we proposed that credit life could be extended by two years for early credits and/or standard credits generated by or traded to approved small refiners (71 FR 15873).

What Commenters Said:

We received comment that the ABT program should provide for extended life of credits generated by small refiners or sold to small refiners. The commenter subsequently goes on to recommend unlimited credit life for credits used by small refiners (addressed below in S&A Section 4.7.5).

Letters:
Countrymark Cooperative, LLP OAR-2005-0036-0471

Our Response:

We are finalizing a modified version of the proposed two-year credit life extension for credits generated by or traded to small refiners. As discussed above in Sections 4.7.3 and 4.7.4, to be consistent with the intent of the provision we have clarified that the two-year credit life extension only applies to standard credits traded to and ultimately used by small refiners.

4.7.4.2 Conflict with 5-Year Statute of Limitations

Under the proposed program, standard credits would have a seven-year life if generated by or traded to small refiners. In the proposal, EPA expressed concern that extending credit life beyond the five-year statute of limitations in the Clean Air Act could create significant enforceability problems. Consequently, we sought comment on provisions that could be included in the regulations to address the enforceability concerns surrounding the extended credit life for small refiner standard credits (71 FR 15873).

What Commenters Said:

The Ad Hoc Coalition of Small Refiners commented that enforceability issues could be addressed in spite of the statute of limitations with a relatively simple approach. They suggested that EPA suspend the right to participate in the credit program to any small refiner that abuses the system. Suspensions could be for a definite time period for first or second violations working up to indefinite suspension if the transgressions are repeated. The Ad Hoc Coalition of Small Refiners concludes that such an approach would address the problem and only punish the wrong-doer(s), if any.

<u>Letters:</u>
Ad Hoc Coalition of Small Refiners OAR-2005-0036-0686

Our Response:

We are finalizing a five-year standard credit life plus a two-year credit life extension for standard credits traded to and ultimately used by small refiners. This could result in a total seven-year standard credit life in certain situations, which could potentially conflict with the five-year statute of limitations. However, EPA need not wait seven years to bring an enforcement action. Enforcement concerns can be mitigated by proactive procedures including: reviewing and processing compliance reports in a timely fashion and understanding which refineries' average benzene levels are above and below the 0.62 vol% standard and thus, which have the potential to be credit users and generators. By investigating questionable credit activities as soon as possible we believe we will be able to take any necessary enforcement action within the five-year statute of limitations period.

4.7.5 Consideration of Unlimited Credit Life

As discussed above, we proposed finite credit life for both early and standard credits. However, in the proposal we acknowledged that there could be some benefits associated with unlimited credit life. Specifically, that unlimited credit life could potentially enhance credit generation and also allow refiners to maintain an ongoing supply of credits in the event of an emergency. However, we also emphasized that unlimited credit life could pose serious enforcement issues. Accordingly, we sought comment on how unlimited credit life could be beneficial to the program and how associated recordkeeping and enforcement issues could be mitigated. We also sought comment on different ways to structure the program (e.g., EPA managing the credit market) that would allow for unlimited credit life (71 FR 15873).

What Commenters Said:

We received several comments supporting the Agency's proposal not to manage credit trading but rather to allow trading with minimal restrictions. However, we also received a comment supporting unlimited credit life. The commenter highlighted that credit generation is an environmental plus and credit use is an environmental negative. The commenter added that unlimited credit life would likely promote credit generation and discourage excessive use in response to credits facing expiration. The commenter believes that credits with unlimited life would likely be stored and used only when the economic value of their use exceeds their market value. The commenter concluded that all credits should have indefinite life in order to maximize their economic value. Another commenter added that credits generated by or traded to small refiners should have unlimited life.

Letters:
Marathon Petroleum Company, LLC. OAR-2005-0036-1008
National Petrochemicals & Refiners Association (NPRA) OAR-2005-0036-0809
Ad Hoc Coalition of Small Refiners OAR-2005-0036-0686
Countrymark Cooperative, LLP OAR-2005-0036-0471

Our Response:

While we acknowledge that there could be some benefits associated with unlimited credit life, we believe that they are outweighed by the potential negatives. First, although unlimited credit life could allow refiners and importers to maintain an ongoing supply of credits in the event of an emergency, it could also encourage hoarding of credits. And if credits were not traded, this would force refineries with more expensive control technologies (who would otherwise rely on credits) to comply with the annual average standard through technological means likely increasing the overall cost of the program. Second, if credits could be used for an indefinite amount of time, credit records would have to be maintained indefinitely – posing a recordkeeping burden. Third, allowing unlimited credit life could make it difficult for EPA to verify compliance with the standard. Even if credit records were maintained indefinitely, the fluid nature of the refining industry could result in enforcement difficulties. For example, if a refiner used credits that were severely dated towards compliance (permissible under a program with unlimited credit life), EPA could experience difficulties tracking down the generator to verify that the credits were indeed properly generated. During the extended intervening period, the generator could have gone out of business or company ownership could have changed several times making it difficult to find or follow a paper trail. For all these reasons, we believe that the disadvantages of unlimited credit life outweigh the potential benefits and thus are finalizing finite credit life for both early and standard credits (including credits generated/used by small refiners).

4.7.6 Credit Trading Provisions

4.7.6.1 Nationwide Trading Allowance

We proposed a nationwide ABT program that would allow refineries and importers to use benzene credits generated or obtained under the ABT program to meet the 0.62 vol% annual average benzene standard in 2011 and beyond (71 FR 15872).

What Commenters Said:

We received a number of comments supporting the proposed ABT program containing no geographic restrictions on credit trading. The commenters believe that the proposed nationwide ABT program will provide maximum flexibility and cost effectiveness, as well as minimize any adverse supply impacts.

<u>Letters:</u>
American Petroleum Institute (API) OAR-2005-0036-0366, OAR-2005-0036-0367
Marathon Petroleum Company, LLC. OAR-2005-0036-1008
National Petroleum & Refiners Association (NPRA) OAR-2005-0036-0809
BP Products North American Inc. OAR-2005-0036-0824, OAR-2005-0036-0837
ExxonMobil OAR-2005-0036-0772, OAR-2005-0036-1013
Flint Hills Resources OAR-2005-0036-0862

Our Response:

As proposed, we are finalizing a nationwide ABT program that does not impose any geographic restrictions on credit trading. Credits may be traded nationwide between refiners or importers as well as within companies to meet the 0.62 vol% national average benzene standard. Early and standard benzene credits may also be used interchangeably towards compliance as permitted by their respective credit life provisions. We believe that restricting credit trading could reduce refiners' incentive to generate credits and hinder trading essential to this program. In addition, as highlighted in Preamble Section VI, the nationwide aspect of the ABT program was an integral component in setting the benzene standard. Without such a program, the 0.62 vol% standard would not be feasible considering cost and other factors.

4.7.6.2 Number of Trades

We proposed that credits must be transferred directly from the refiner or importer generating them to the party that intends to use them for compliance purposes. This ensures that the parties purchasing them are better able to assess the likelihood that the credits are valid. An exception exists where a credit generator transfers credits to a refiner or importer who inadvertently cannot use all the credits. In this case, the credits can be transferred a second time to another refiner or importer. After the second trade, the credits must be used or terminated. In the proposal, we requested comment on whether more than two trades should be allowed – specifically, whether three or four trades were more appropriate and/or more beneficial to the program (71 FR 15876).

What Commenters Said:

We received comments supporting a maximum number of two trades as well as comments suggesting the ability to trade credits up to four times before credits would have to be terminated.

Letters:
Caribbean Petroleum Corporation OAR-2005-0036-1010
Colonial Oil Industries OAR-2005-0036-0990
Gladieux Trading & Marketing Co., LP OAR-2005-0036-0972
U.S. Oil & Refining Co. OAR-2005-0036-0992
American Lung Association OAR-2005-0036-0868, OAR-2005-0036-0365

Our Response:

The commenters suggesting four trades did not provide any rationale supporting the need for an additional number of trades. They did not address how the additional flexibility would be beneficial to the program nor did they address how the added flexibility would outweigh the enforcement concerns. As a result, we are finalizing a maximum number of two trades. Not only is this provision consistent with other fuel rulemakings, we believe it strikes a balance between flexibility and enforceability. Allowing more than one trade provides for a “safety valve” in the event that credits obtained cannot be used within the credit life provisions. Allowing the fewest number of trades ensures that both credit purchasers and EPA are better able to assess the validity of credits.

4.7.6.3 Credit Brokering/Ownership

We proposed no prohibitions against brokers facilitating the transfer of credits from one party to another. Any person can act as a credit broker, regardless of whether such person is a refiner or importer, although no credit “ownership” transfers to the broker. This prohibition on outside parties taking ownership of credits was promulgated in response to problems encountered during the unleaded gasoline program and has since appeared in subsequent fuels rulemakings. To reevaluate potential stakeholder interest in removing this prohibition, EPA sought comment on this provision in the proposal -- specifically, whether there were potential benefits to allowing other parties to take ownership of credits and how such a program would be enforced (71 FR 15876).

What Commenters Said:

We received comments from several companies all supporting the prohibition against brokers taking ownership of credits.

Letters:
Caribbean Petroleum Corporation OAR-2005-0036-1010
Colonial Oil Industries OAR-2005-0036-0990
Gladieux Trading & Marketing Co., LP OAR-2005-0036-0972
U.S. Oil & Refining Co. OAR-2005-0036-0992

Our Response:

Since we did not receive any adverse comments, we continue to believe that our existing prohibition on outside parties taking ownership of credits is appropriate. As such, we are finalizing the proposed program where brokers can facilitate credit transfers but not take "ownership" of credits. Not only is this provision consistent with other ABT programs for mobile sources and their fuels, it is sufficiently flexible while preserving adequate means for enforcement.

4.7.7 Exclusion of California Gasoline from ABT Program

Despite the fact that California gasoline is not covered by this program, EPA sought comment on whether and how credits could be generated based on California gasoline benzene reductions and applied toward non-California gasoline compliance (71 FR 15873).

What Commenters Said:

One commenter agreed with our proposal and opposed credits being generated on behalf of California gasoline benzene reductions for use outside of California. Another commenter responded that California refineries should be allowed to participate in the ABT program. .

Letters:
Marathon Petroleum Company, LLC. OAR-2005-0036-1008
American Lung Association OAR-2005-0036-0868, OAR-2005-0036-0365

Our Response:

The commenter supporting the inclusion of California refineries did not provide any rationale why California gasoline specifically should be included in the ABT program. As a result, we are finalizing the proposed program which excludes California gasoline. As described below, we believe that including California gasoline in the ABT program would be a rigorous task with very few benefits.

First, we do not currently receive batch reports for California gasoline under the existing RFG/Anti-Dumping reporting requirements. Therefore, in order for credits to be generated (based on baseline benzene reductions) California gasoline refineries would first need to provide EPA with the appropriate 2004-2005 batch reports in order to establish individual refinery benzene baselines. Additionally, these refineries would need to provide EPA with such reports in the future (in addition to the CARB compliance reports/information required under the California Phase 3 Reformulated Gasoline (CaRFG3) Program). On the other hand, if we allowed credits to be generated for overcomplying with the 0.62 vol% standard (as opposed to making reductions from an individual benzene baseline), this would mostly likely result in windfall credit generation. As of 2004, California gasoline benzene levels were already around 0.62 vol% on average (based on data provided to EPA by CARB). As a result, contrary to the intent of the program, most California gasoline refineries would be eligible to generate credits for doing nothing at all. For these reasons, we are finalizing the proposed ABT provision which excludes California gasoline from generating credits.

4.8 Effects on Fuel and/or Energy Supply, Distribution, and Use

4.8.1 Energy Impacts

What Commenters Said:

The American Petroleum Institute (API) commented that Draft RIA Table 9.610 characterizes estimated changes in energy use resulting from the (proposed) rule as small, but the commenter noted that the change is positive—i.e., more energy is needed to accomplish the same fuel delivery.

ExxonMobil, NPRA, and MPC commented that they believe that proposed MSAT2 standards are a significant energy action, and that EPA has incorrectly stated that the rule is not a “significant energy action” (per EO 123211). They further stated that they do not agree with EPA’s belief that the reduced volume (about 23,500 b/d) of reformate available for gasoline production due to MSAT2 will be made up through other processes with little or no net reduction in gasoline production. The commenters stated that they do not accept the assumption that this volume reduction can be replaced easily.

NPRA and Marathon Petroleum Company also commented that EPA projected that the annual aggregate costs associated with the rule will be $185.5 million in 2011 (and higher after 2011); based on these cost projections, the commenter stated that it believes the program is a significant energy action because is exceeds $100 million (per section 3(f) of E.O. 12866).

<u>Letters:</u>
American Petroleum Institute (API) OAR-2005-0036-0884
ExxonMobil Refining & Supply Company OAR-2005-0036-0772
Marathon Petroleum Company LLC OAR-2005-0036-1008
National Petrochemical & Refiners Association (NPRA) OAR-2005-0036-0809

Our Response:

Several commenters expressed their view that the benzene control program will have a major adverse impact on energy supply. In its guidance document to Executive Order numbered 13211, the Office of Management and Budget (OMB) defined specific criteria for determining whether any rulemaking has a significant adverse effect on energy supply, distribution and use. We identified three significant adverse impact criteria contained in the OMB guidance document which could be relevant. The first criteria relates to electricity demand. OMB’s guidance document to EO 13211 states that a regulatory action has caused a significant adverse effect on energy if the supply of electricity is reduced by a billion kilowatt hours per year. As estimated by our contractor using its linear programming refinery model (which estimate we have analyzed and agree with), the benzene reductions required by the final rule should result in less than 290 million kilowatt-hours per year of additional electricity demand.[16] This demand would result from the application of benzene control equipment and other refinery changes associated with gasoline benzene control. This additional demand for electricity is below the trigger of 1 billion kilowatt-hours per year of electricity identified in the OMB guidance document that would be considered a significant impact on electricity supply.

OMB's guidance document to EO 13211 also states that a regulatory action has caused a significant adverse effect on energy if natural gas supply is impacted by 25 million standard cubic feet per year, which equates to about 25 billion BTUs per year. Based on the linear program modeling work cited above, our final benzene control program is expected to cause an additional demand of 5.5 billion BTUs per year of natural gas, which is lower than the trigger of 25 billion BTUs per year that would define a significant impact on natural gas supply.

Based on OMB's guidance document, the last potential trigger for how this rulemaking could cause a significant adverse effect on energy supply, distribution and use relates to decreases in fuel supply. Several commenters raised this as an issue related to EO 13211, while others raised it as a more general issue. OMB's guidance document to EO 13211 states that a regulatory action has caused a significant adverse effect on energy if the supply of fuel is decreased by 4,000 barrels per day. In this case we interpret the term fuel to mean gasoline.

Compliance with the benzene standards in the rule will not automatically reduce gasoline supply. Refineries which are able to meet the standards through benzene saturation, for example, will not incur any volumetric reductions in gasoline production. Gasoline production would be decreased only at refineries utilizing benzene extraction (i.e. reformate extraction), since removing benzene from the gasoline pool via extraction reduces the overall volume of gasoline. We in fact project that refineries will extract an additional 12,500 barrels of benzene per day, or 192 million gallons per year, in the course of complying with the fully phased-in benzene control program.[17] This is equivalent to about 13,375 barrels per day of gasoline (or about 0.1 percent of U.S. gasoline production) when the higher energy density of benzene is taken into account.

At first blush, this appears to exceed the significant adverse effect threshold. However, we believe that the net effect of the rule on gasoline supply will be far less, potentially zero, and will not exceed the 4000 barrels of fuel supply threshold. This is because we expect the increase in extraction of benzene from gasoline to occur with or without the final benzene control program. Using Chemical Market Associates

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[16] Kolb, Jeff, Abt Associates, Estimated Changes in Energy Use, LP Refinery Model Output provided to EPA under contract WA 0-01, EP-C-06-094, December 27, 2006.
[17] Kolb, Jeff, Abt Associates, Estimated Changes in Energy Use, LP Refinery Model Output provided to EPA under contract WA 0-01, EP-C-06-094, December 27, 2006.

Incorporated's (CMAI) estimate of a 2.4 percent annual growth in benzene demand, we expect that U.S. demand for benzene will increase by 600 million gallons from 2007 to 2015, the years that the final benzene control program is expected to phase-in. Assuming as is reasonable that reformate extraction continues to supply about 40 percent of the total benzene supply,[18] then reformate extraction is expected to supply about 250 million gallons additional benzene over the eight year benzene program phase-in period. This exceeds the amount of reformate extraction that we project would occur for refiners using benzene extraction to comply with the gasoline benzene standards in this rule, provided, as is reasonable, that the benzene extraction occurs throughout the entire phase-in period. Only in the highly unlikely event that all refiners projected to use benzene extraction to comply with the final benzene control program install extraction equipment in a single year would the increased benzene supply exceed projected benzene demand (by a factor of roughly two times the yearly increase in total benzene demand), potentially raising issues of reduction in gasoline supply under the Executive Order.[19]

Even under this unlikely scenario of all the projected benzene extraction occurring in a single year, the benzene market would likely adjust to rebalance both the benzene market and the gasoline supply. Selective toluene disproportionation and toluene hydrodealkylation are higher cost benzene production technologies that contributed about 290 million gallons per year of benzene to the U.S. petrochemical market in the year 2002. If there were to be a drastically increased volume of benzene extraction from refineries, there would likely be correspondingly less use of these two marginal, higher cost benzene production processes which would rebalance the benzene supply/demand market. Assuming (reasonably) that these two benzene production processes temporally reduce their output to rebalance benzene supply, the feedstock toluene would presumably stay in the gasoline pool essentially negating the potential impact that reducing benzene from gasoline supply would otherwise cause. We therefore do not see gasoline volumes being significantly reduced as a result of benzene extraction occurring as a result of requirements of this rule.[20]

We thus do not accept the comments that this rule would have a significant adverse impact on energy supply, distribution, or use for purposes of the Executive Order, or for purposes of our consideration of energy issues required by section 202 (l)

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[18] This is a reasonable assumption because the contribution of reformate extraction to the total supply of benzene in North America has remained fairly constant from 1998 to 2002, the years that CMAI provides benzene supply data in their Benzene report.

[19] Increased benzene extraction for compliance as modeled by the cost analysis is likely to phase in over the entire phase in period of the benzene program because of the implementation nature of the various benzene extraction projects. Of the total 16 extraction units expected to be revamped or newly installed by refiners complying with the benzene program, 13 of them are revamps. Because revamp projects are extremely variable in nature with a similar variation in cost, they can be completed over a time period which ranges from almost immediately to 4 or even 5 more years our for more complex revamps. The 3 grassroots extraction units will likely be installed the latest of all the benzene extraction projects because they require extensive installs, both for onsite and offsite capital. Thus these projected benzene extraction units will be installed throughout the phase-in period.

[20] We conservatively did not reduce our program cost estimates due to any of the modeled benzene extraction occurring in the baseline, nor did we reduce our cost estimate based on any toluene reentering the gasoline pool from reduced benzene formation from toluene feedstocks.

(2) of the Act. In this regard, we note further that we do not believe that there will be any reduction (and there may be an increase) in fuel supply from the rule's vehicle standards, and that the standards for portable fuel containers will result in significant fuel savings by reducing evaporative losses (estimated to be about 66 million gallons of gasoline savings per year in 2014).

One commenter stated that this rulemaking has a significant impact on gasoline supply because it exceeds $100 million per year cost threshold of EO 12866. However, EO 12866 sets a trigger which determines whether a rulemaking has a significant economic impact, but that does not also indicate that a rulemaking has a significant impact on energy supply. For that analysis, we rely on the criteria for EO 13211, as just discussed above.

4.8.2 Impacts on Gasoline Supply

What Commenters Said:

The New York Department of Environmental Conservation commented that it believes that a reduction in gasoline benzene is good, but raises the question of how the lost volume will be made up and whether the volume of other undesirable constituents will increase.

At the public hearing, the National Petrochemical and Refiners Association (NPRA) also commented that, in proposing new standards for fuel formulations or any other rules affecting refinery and/or petrochemical facilities, the Agency needs to be aware of the total impact these programs may have on fuel supply.

NPRA and Marathon Petroleum Company (MPC) commented that they believe that the Agency should re-evaluate the rule's potential impacts on gasoline supply. The commenters further stated that they do not agree with the Agency's optimistic projections that the net effect of the MSAT2 program on gasoline supplies will be potentially zero. They stated that they also do not agree with the statements that the proposed ABT program with the 0.62 vol% benzene level is feasible, would be met without extreme economic consequences, and that all refineries would be able to comply. The commenters noted that, in response to the benzene standards, they believe that refineries could choose to close, reduce gasoline production, or export more gasoline, all of which could adversely affect gasoline supplies. The commenters further stated that they believe that finalization of the rule as proposed could result in lower gasoline imports if importers do not wish to incur the additional expense of purchasing credits from domestic refineries.

The commenters also stated that they believe that gasoline supplies will also be adversely affected if the rule results in reduced gasoline imports. The commenters noted that the lower benzene level may limit gasoline imports into the U.S. from areas that do not have gasoline benzene controls, such as Central and South America and the

Caribbean. The commenters suggested that EPA consider whether such import restrictions will have an adverse impact on US gasoline markets.

NPRA and Marathon Petroleum Company also commented that they believe that the rule would have an adverse effect on domestic gasoline supplies if refineries closed, reduced gasoline production, and/or exported more gasoline. The commenter further stated that refineries may not implement benzene content reduction strategies as the proposed rule predicted, and that it does not have confidence that the Agency has estimated correctly for every refinery.

<u>Letters:</u>
Marathon Petroleum Company LLC OAR-2005-0036-1008
National Petrochemical & Refiners Association (NPRA) OAR-2005-0036-0809
New York State Department of Environmental Conservation OAR-2005-0036-0722

Our Response:

The commenters expressed their concern that the new benzene program could create a regulatory hurdle that will result in less gasoline being imported into the U.S. After reviewing the benzene levels of imported gasoline and considering the flexibility of our benzene program, we don't think that imported gasoline volumes will be affected significantly. About half of imported gasoline is imported into the RFG market which already requires lower benzene levels. A review of the benzene levels of imported gasoline reveals that it averages 0.75 vol% benzene, which is substantially lower than the roughly 1.0 vol% current national average benzene level for U.S. gasoline. Even assuming that foreign refiners will not be willing to further reduce their gasoline benzene levels, if their gasoline benzene levels are above 0.62 vol% benzene, they could continue to import gasoline that exceeds the 0.62 vol% benzene standard and purchase credits. Only 0.5% of imported gasoline's volume exceeds the 1.3 maximum average benzene standard and is at risk of being rejected from the U.S. gasoline market. Even this higher benzene gasoline could continue to be brought into the U.S. if the importers balance this higher benzene gasoline with gasoline which contains less than 1.3 vol% benzene resulting in a combined gasoline pool which averages less than 1.3 vol% benzene.

Two commenters stated that gasoline supply could be impacted adversely if some refiners closed as a result of the benzene program. Based on the flexibilities provided by the benzene program, we do not project any closures in our detailed economic analysis found in chapter 9 of the RIA. The ABT program provides several flexibilities, such as the availability of credits or deficit carry-forward, which will help to reduce the cost of compliance with the annual average gasoline benzene standard. For smaller refineries that our modeling estimates would be faced with potentially high costs to comply with the 1.3 maximum average standard, we believe that there are other lower cost means for these refineries to reduce their benzene levels which are not captured by our refinery cost modeling (see section 9.6.1 of Chapter 9 of the RIA). Finally, the final rule provides numerous exemption opportunities for refiners that can demonstrate that the rule causes them extreme hardship that leaves refineries many alternatives to closure.

Finally, one commenter asked whether the decrease in gasoline benzene content will cause the content of other undesirable constituents in gasoline to increase. We do not project this to be the case. Some of the benzene control technologies (notably benzene saturation) chemically convert the benzene to cyclohexane, a petroleum compound not known to be a human carcinogen. Most of the benzene reducing technologies will cause a small decrease in the octane level of the treated gasoline. This octane loss will likely be made up by the addition of ethanol, since ethanol has become the constituent of choice for increasing the octane of the gasoline pool. See section VI.A.1.b.i of the preamble to the final rule.

4.8.3 Other

What Commenters Said:

Sinclair Oil Corporation, Flying J. Inc., Suncor Energy (U.S.A.) Inc., and Tesoro Corporation commented that they believe that a further economic disadvantage PADD 4 and 5 refineries face with benzene control is the distance from, and lack of access to, benzene markets. The commenters stated that they believe this may be one reason why many Gulf Coast refineries manufacture gasoline with benzene levels lower than the nation at large; and conversely, PADD 4 and 5 refineries that rail benzene to petrochemical plants in the Gulf Coast region pay a high transportation penalty to sell benzene to these facilities.

MPC commented that it believes that, due to the wide range of starting points, compliance costs will be low for some refineries and higher for others. The commenter stated that it believes that the variability in the selection of benzene control strategies (as predicted in the proposed rule’s refinery cost model) depends on existing equipment at the refinery, proximity to the petrochemical market, and estimated benzene reduction technology costs compared to the cost of buying a credit. However, the commenter noted, it was assumed in the proposal that all refineries will choose to either make the necessary investments or will purchase credits—the commenter stated that it believes that EPA made no attempt to identify these refineries or their cumulative volume impact on the US gasoline pool.

ExxonMobil commented that it believes that EPA should estimate the potential adverse impact the proposal will have on criteria pollutants and CO_2 emissions at refineries.

Letters:
ExxonMobil Refining & Supply Company OAR-2005-0036-0772
Marathon Petroleum Company LLC OAR-2005-0036-1008

Sinclair Oil Corporation, Flying J. Inc., Suncor Energy (U.S.A.) Inc., and Tesoro Corporation OAR-2005-0036-0989

Our Response:

Several commenters commented about the cost of compliance for refineries in PADDs 4 and 5, particularly about the economic inability to use benzene extraction as a benzene control technology. We agree that the refiners in PADDs 4 and 5 are unlikely to have the ability to use extraction to reduce benzene levels at their refineries due to lack of access to benzene markets without disproportionate transport costs. Our modeling is in fact consistent with this belief. Also these refineries tend to have higher starting benzene levels and poorer economies in scale (they are smaller refineries) resulting in higher compliance costs for the refineries in these PADDs. For this reason, our modeling projects that several refineries in PADDs 4 and 5 will rely on the ABT program to purchase credits, reducing their overall cost of complying with the annual average benzene standard.

One commenter stated that there is a wide range in compliance strategies as well as compliance costs, as identified in the regulatory documents. However, the commenter stated that we did not identify which refineries will take what benzene control steps, nor did we attempt to identify the impact on gasoline supply. Addressing the first comment, our refinery-by-refinery analysis is built in part upon confidential business information, and our projections of the steps they might take to reduce their benzene levels are considered sensitive information. Therefore, we cannot reveal our refinery-by-refinery projections of which refineries take what steps to reduce their benzene levels, although we did report the projected use of benzene control technologies more generally. As for the second comment, as described above in our response to comment 4.8.1, we do not believe that there will be a net impact on gasoline supply due to benzene extraction used by U.S. refiners when complying with this rulemaking. We further concluded in our response to comment 4.8.2 that imports are not expected to decrease due to the rule's requirements. In sum, we don't expect any significant decrease in gasoline supply caused by fuel (or other) requirements of the rule.

One commenter stated that EPA should estimate the emissions increases in CO_2 and criteria pollutants at refineries caused by the benzene program. The analysis conducted by our contractor to estimate the energy and supply impacts of the benzene program provided detailed estimates of the fuel and electricity consumed at refineries in reducing the benzene levels of gasoline.[21] We used these fuel and electricity demand estimates along with emission factors for carbon dioxide and criteria pollutants to derive emission estimates for carbon dioxide and criteria pollutants at refineries.

The national increase in fuel demand, which is assumed to be natural gas, associated with application of benzene control technologies is 16 trillion BTUs per year which includes the natural gas used in furnaces and steam generation. Of that 16 trillion,

[21] Kolb, Jeff, Abt Associates, Estimated Changes in Energy Use, LP Refinery Model Output provided to EPA under contract WA 0-01, EP-C-06-094, December 27, 2006.

9.8 trillion BTUs per year comprises feedstocks for the production of hydrogen (the relevance of which is discussed below). Additional energy demand and emissions occur through the consumption of electricity. Electricity demand is estimated to increase by 731 kilowatt-hours. Electricity is equivalent to 3400 BTUs per kilowatt-hour and electricity generation is estimated to be about 37 percent efficient. Thus, electricity generation is responsible for about 0.06 trillion BTUs per year of additional energy consumption.

To estimate the emissions of carbon dioxide and criteria pollutants at refineries we used emission factors for deriving the emissions from the increased demand for natural gas and electricity. The emission factors that we used are the criteria emission factors for a gasoline hydrotreater provided to us by Mobil Oil.[22] Since the natural gas used for hydrogen production was consumed as a feedstock and not burned, we did not use that part of the natural gas consumption to derive criteria emission estimates, although we did consider it along with the rest of the natural gas and electricity consumption for carbon dioxide emissions.

The emission factors for the use of energy are summarized in the Table below. The NOx emission factor is expressed as a range. The lower value reflects the emissions from the use of ultra-low NOx burners, while the upper number reflects the emissions of conventional burners. The rest of the criteria emissions are estimated based on single point estimates for their emission factors. The emission factor for carbon dioxide is estimated from the combustion of an equal blend of natural gas and liquid petroleum gas, which represents the combustion of refinery gas. The combustion of this blend in refinery fuel is estimated to yield 143,000 lbs of CO_2 per billion BTU of fuel consumed. We assume that electricity has the same emission factors as refinery fuel gas, which is very simplistic. Electricity can be generated from coal, fuel oil, natural gas, nuclear, hydroelectric and other renewable energy sources. All these energy sources can contribute to higher and lower emission levels of pollutants than that assumed based on refinery fuel gas, so using the criteria pollutant emission factors of refinery fuel gas may be roughly representative as well. The small amount of total energy consumed from the generation of electricity means that the uncertainty around the emissions associated from electricity production will have little impact on the emissions estimates.

Summary of Emission Factors and Refinery Emissions Attributed to the Benzene Program

	Emission Factors (lbs per Billion BTU)	Change in 2012 Emissions (tons/yr)
CO_2	143,000	1,145,000
NOx	35 – 140	108 – 433
VOC	25	77
CO	35	108

[22] While units which reduce gasoline benzene levels are different from those that desulfurize gasoline, the primary units that use energy, including furnaces and boilers, are very similar. Thus, the emission factors derived for gasoline desulfurization units can be applied to benzene reducing technologies.

Particulate	3.0	9
SOx	13	40

The table shows that CO_2 emissions at refineries are estimated to increase by a little more than a million tons per year, and the refinery criteria emissions are estimated to increase within a range of 9 to 430 tons per year.

4.9 Small Refiner and Other Hardship Provisions

4.9.1 Small Refiner Provisions

4.9.1.1 Support for Small Refiner Provisions

What Commenters Said:

We received several comments supporting provisions for small refiners in the MSAT2 rule, especially the four-year period of additional lead-time. The commenters noted that they believe that this provision is very important because small refiners generally lack the resources available to large companies and require additional time to acquire capital and complete equipment modifications.

The Ad Hoc Coalition of Small Business Refiners (Small Refiners) further commented that they agree with EPA's rationale for providing small refiner provisions and stated that they believe EPA expressed well the special needs of small refiners.

Some commenters suggested that EPA allow less stringent or alternate standards indefinitely for small refiners. One commenter stated that it believes the cost to meet the proposed 0.62 vol% benzene standard will be inordinate, and that a loss of marketable gasoline due to benzene reduction would cause it to incur significant economic hardship. The commenter suggested that provisions such as delayed compliance, and those that will either allow small refiners to meet alternate benzene standards or contain a credit program that will make compliance economically possible, should be part of the final rule. Another commenter stated that small refiners are still concerned about the impact of this regulation on their long term viability; and that while the amount of gasoline that small refiners produce is not large, it is critical both to supply and price. The commenter thus stated that it believes this warrants a relaxing of the benzene requirements for small refiners (an action it believes would not impact the MSAT2 program), and further requested that EPA reevaluate whether a 0.62% benzene level for small refiners actually makes sense, considering that small refiners are located all over the United States and the amount of small-refiner-produced gasoline consumed in any given area is minimal.

In addition, Countrymark commented that it believes that the regulation should contain a provision for individual hardship relief for small refiners on a long-term basis if they are unable to reduce the benzene level required by the regulations. The commenter noted that it is possible that a small refiner could install benzene removal equipment and still need to purchase credits; that the purchase of credits would be so costly that it could not compete in the gasoline market; or that a small refiner still could not comply even if it was financially able to install the removal equipment. Countrymark commented that, in either case, it believes such a refiner should be allowed to continue to operate at a higher benzene level until it is possible for it to obtain equipment that would be effective or the credit costs reduced. The commenter suggested that in such cases of hardship, EPA should consider whatever action is necessary to allow the small refiner to continue to produce gasoline. The commenter further stated that it believes it is important for EPA to recognize the need to keep every small refiner a viable producer of gasoline for the market.

Letters:
Ad Hoc Coalition of Small Business Refiners OAR-2005-0036-0686
Caribbean Petroleum Corporation OAR-2005-0036-1010
Countrymark Cooperative, LLP OAR-2005-0036-0471
Silver Eagle Refining, Inc. OAR-2005-0036-0839
U.S. Oil & Refining Company OAR-2005-0036-0992

Our Response:

As stated in the preamble to the final rule, we are finalizing many of the provisions that were proposed which were specific to small refiners. We believe that small refiners generally have greater difficulty than larger companies (including those large companies that own small-capacity refineries) in raising capital for investing in benzene control equipment. We also believe that small refiners are likely to have more difficulty in competing for engineering resources and completing construction of the needed benzene control (and any necessary octane recovery) equipment in time to meet the required standards. We have chosen to finalize a four-year period of additional lead time for small refiners, until January 1, 2015 to comply with the 0.62 vol% annual average benzene standard. This amount of lead time was supported by all commenters on the issue. We are also finalizing 4 years of additional lead time, until July 1, 2016, for small refiners to meet the 1.3 vol% refinery maximum average benzene standard. As discussed more fully below, we are also finalizing a review of the ABT program after the first year of the program. The four-year lead time period will provide small refiners with nearly three years of lead time following the review to complete any necessary capital projects.

We do not agree with the comment that small refiners, as a class, should simply not be subject to the benzene standards in the rule. As shown in chapters 9 and 14 of the RIA, as well as in the preamble to the final rule, small refiners can achieve the standards adopted in the rule. Exempting small refiners as a class would therefore result in a fuel program that did not obtain the greatest emission reductions of toxics achievable from motor vehicle fuels. We believe that individual small refineries incurring extreme economic hardship as a result of the rule may be eligible for some type of hardship waiver, as explained below. Any such relief, however, would be on a case-by-case basis reflecting the refiner's situation after making good faith efforts to comply, and should not (and legally cannot) be adopted now for the entire class of small refiners.

We do accept the comment that it is possible that for some small refiners, compliance with the 0.62 vol% annual average standard through purchase of credits may prove to be infeasible and have added an additional hardship provision to the final rule to accommodate such a possibility. As discussed in more detail in section VI.A.3.a.iii of the preamble to the final rule, we are finalizing an additional hardship provision exclusively for approved small refiners to cover the case of a small refiner for which compliance with the 0.62 vol% annual average standard would be feasible only through the purchase of credits, but for whom the purchase of credits is not practically or economically feasible. This hardship provision will only be available following the ABT program review, as the most accurate information to assess credit availability and the workings of the credit market are necessary to evaluate this type of claim of hardship. Hardship relief under this provision will only be afforded to a small refiner on a case-by-case basis, and must be based on a showing by the refiner of the practical or economic difficulty in acquiring credits for compliance with the 0.62 vol% benzene standard. Hardship relief under this provision, if granted, would consist of a further delay, on an individual refinery basis, for up to two years. Following the two years, a small refiner will be allowed to request one or more extensions of the compliance date for the 0.62 vol% annual average benzene standard until the refinery's material situation has changed.

In addition, the general hardship relief provisions discussed in section VI.A.3.b of the preamble are available to any refiner, including the situations that could arise for small refiners. This includes hardship in meeting the 1.3 vol% maximum average standard, as discussed below.

4.9.1.2 ABT Program

What Commenters Said:

The Small Refiners commented that, in addition to additional lead-time, they strongly endorse: a nationwide ABT program which allows small refiners to earn credits and also includes some provisions to encourage more credit trading to small refiners (i.e., the extension of credit life by two years if generated by, or traded to, small refiners); a review of the ABT program and the small refiner flexibility options by 2012, including the submission of pre-compliance reports; and consideration of additional small refiner provisions on a case-by-case basis, depending upon the results of the ABT program review. In addition, the commenters stated that equally as significant are the design and review of the ABT program. The Small Refiners noted that many small refiners estimate their benzene reduction costs to be higher on a per gallon basis than EPA's estimates, thus they believe that, for many, the only feasible approach [to meet the 0.62 vol% benzene standard] will be to purchase credits. The Small Refiners stated that compliance with desulfurization regulations and planned refinery expansions are expected to increase benzene production. Therefore, the commenters stated that they believe it is essential that the availability and cost of credits be known as soon as possible (well before the small refiner compliance deadline) and that steps must be taken to ensure a functional credit market with reasonable credit costs.

The Small Refiners also commented that they believe that provisions should be included to address enforceability with regard to extended credit life for small refiner standard credits in light of the five-year statute of limitations on EPA enforcement activities. The commenters suggested that enforceability could be addressed in spite of the statute of limitations with a relatively simple approach of suspending the right to participate in the credit program of any small refiner that abuses the system. The commenters also stated that they believe that the proposed requirement for annual compliance reports will provide a relevant data base, and that suspensions could be for a definite period of time for first or second violations, working up to indefinite suspension if transgressions are repeated.

Letters:

Ad Hoc Coalition of Small Business Refiners	OAR-2005-0036-0686

Our Response:

We are in fact finalizing an early credit generation provision to allow small refiners the opportunity to generate early credits for reductions of at least ten percent of the refiner's 2004-2005 benzene levels prior to the small refiner compliance deadline on January 1, 2015. We believe that early credit generation opportunities for small refiners will provide more credits for the MSAT2 ABT program. Further, it will help to achieve the air quality goals of the MSAT2 program earlier than otherwise required, as there will be an incentive for these refiners to reduce their benzene levels prior to the small refiner compliance deadlines. The small refiner early credit generation period will be from June 1, 2007 to December 31, 2014, after which standard credits may be generated indefinitely for those that overcomply with the 0.62 vol% annual average standard.

We are also finalizing provisions for extended credit life, to increase the certainty that credits will be available. We believe that this will encourage trading to small refiners. We are finalizing that standard credits traded to, and ultimately used by, small refiners will receive an additional two years of credit life. The extension does not apply to early credits because refiners already have an incentive to trade early credits to small refiners. Based on the nature of the early credit life program (three-year life based on the start of the program in 2011) and small refiners' delayed program start date in 2015, early credits traded to small refiners are already valid for an additional four years. Further, we do not believe that there is a need to extend credit life for credits generated by small refiners, because in this event, the small refiner would already have the utmost certainly that the credits would be available for use. Regarding the commenters' note about the five-year statute of limitations on EPA enforcement activities, this is discussed fully in section 4.7.4.2, above.

4.9.1.3 ABT Program Review

What Commenters Said:

A number of commenters stated that they support the proposed EPA review of the ABT program in 2011. The commenters reiterated that a review of both the credit program and the small refiner flexibility options by 2012 is essential because of the critical importance to small refiners of a viable credit system and the fact that some small refiners believe that it will be economically and/or technically necessary for them to purchase and use credits.

The Small Refiners specifically requested that EPA include small refiners in the development of the final design for the program review and in the review process/credit program evaluation itself. The commenters stated that they believe it will be important that the review include an evaluation of small refiner benzene reduction capital equipment and operating costs compared with the cost of credits. The commenters further suggested that EPA perform annual reviews to assess potential changes in the credit marketplace. The Small Refiners also offered comments on elements that they believe should be included in the review, and actions that might follow the review:

1) Revisiting the small refiner provisions if it is found that the credit trading market does not exist to a sufficient degree to allow small refiners to purchase credits, or that credits are only available at a cost-prohibitive price. Revisions could include additional hardship provisions on a case-by-case basis, such as further delay or relaxation of the standard with the possibility of multiple extensions until the refinery's material situation changes.

2) Options to either help the credit market or help small refiners gain access to credits if it is found that there is not an ample supply of credits or that small refiners are having difficulty obtaining them. One option suggested was the "creation" of credits by EPA to introduce into the credit market, or imposing additional requirements to encourage trading with small refiners (e.g., requiring a percentage of all credits be set aside for small refiners only, requiring that some credits be made available to small refiners before they can be sold to any other refiners).

<u>Letters:</u>

Ad Hoc Coalition of Small Business Refiners OAR-2005-0036-0686
Caribbean Petroleum Corporation OAR-2005-0036-1010
Colonial Oil Industries, Inc. OAR-2005-0036-0990
Gladieux Trading & Marketing Co., L.P. OAR-2005-0036-0972
U.S. Oil & Refining Company OAR-2005-0036-0992

Our Response:

EPA will review the ABT program (and thus, the small refiner flexibility options) in 2012, one year after the general program for the 0.62 vol% annual average benzene standard begins. Coupled with the small refiner four-year additional lead time provision, the ABT program review after the first year of the overall program will provide small refiners with roughly more three years, after learning the results of the review, to obtain financing and perform engineering and construction with respect to that standard. In part to support the review, we are requiring that refiners submit pre-compliance reports, similar to those required under the highway and nonroad diesel programs. This review will take into account the number of early credits generated industry-wide each year prior to the start of the MSAT2 program, as well as the number of credits generated and transferred during the first year of the overall benzene control program. Section VI.A.2.a.iii of the preamble to the final rule contains detailed information on the requirements for the ABT pre-compliance reports. EPA will publish generalized summaries (to maintain the confidentiality of information from individual refiners submitted in the reports) of the reports annually. We will also take input on how to conduct the review and potential options to consider if a viable credit market does not exist.

If, following the review, EPA finds that the credit market is significantly at odds with the assumptions underlying the final rule provisions for small refiners, we will revisit the provisions to determine whether or not they should be altered or whether EPA can assist the credit market (and small refiners' access to credits). Further, as noted above in section 4.9.1.1, if we find that some small refiners still cannot comply with the 0.62 vol% benzene standard even with a viable credit market and that credit purchase is the refiner's only option for compliance with the standard, we are finalizing an additional hardship provision to potentially assist those small refiners.

4.9.1.4 Concerns with 1.3 Vol% Refinery Maximum Average Standard

What Commenters Said:

Representatives of small refiners were critical of the possibility of adding a 1.3 vol% refinery maximum average to the fuel benzene standards. They expressed their concerns in both written and oral statements to the agency, challenging both the maximum average standard and the procedures by which it was adopted. They maintain that the imposition of a 1.3 vol% refinery maximum average violates the Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 because the Small Business Advocacy Review (SBAR) Panel did not have the opportunity to review the impacts of such a standard on small businesses. At a minimum, they believe EPA would need to present the maximum average provision to the Panel for its consideration prior to including it as part of a final rule (citing 5 U.S.C. § 609). They add that the possibility of a maximum average was never raised during the SBAR Panel process which assessed the impact of an MSAT2 rulemaking. They continue that had it been, the small refiner representatives would have opposed the concept as greatly damaging to their segment of the industry. They further contend that such a maximum average significantly changes the economics of small refiner compliance and that it should (and must) be considered by an SBAR Panel before a rule is finalized.

The commenters also stated that there are at least eight small refiners that have benzene levels above 1.3 vol%. The commenters also expressed concerns such as maintaining octane levels, costs for transportation of extracted benzene, and ability to locate other treatment facilities. More generally, they stated that applying the maximum average to small refiners is at odds with the premise of the proposed rule: that unlimited ABT is needed to provide sufficient flexibilities for refiners which otherwise would need to make expensive capital investments. They stated that for many small refineries, the cost of meeting the 1.3% level will require significant capital investment and likely would remove them from the credit buying market not only to meet the 1.3 vol% levels, but also at levels below 1.3%. They continued that the inability of small refiners currently above 1.3% benzene gasoline levels to comply with credits threatens the very existence of those refiners and calls into question EPA's assumptions regarding impact of the rule on fuel supply. They maintain that EPA itself recognized that absent small refiner flexibilities, EPA would likely have to consider setting a less stringent benzene standard or delaying the overall program to diminish burden on small refineries (citing 71 FR 15877). Given these concerns about the inability to use credits to meet levels above 1.3 vol%, thus they suggested that EPA should allow small refiners to use credits for compliance with the 1.3 vol% refinery maximum average, with either a PADD restriction on credit trading or discounting credits used to meet the 1.3 vol% standard.

Letters:

Ad-Hoc Coalition of Small Business Refiners	OAR-2005-0036 (late comments)

Our Response:

EPA disagrees that adopting a refinery maximum average in the final rule without specifically presenting the option for consideration by the section 609 SBAR Panel, or without reconvening that panel, violates the requirements of the Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act of 1996. Section 609 imposes various procedural requirements for gathering comments from small entities when EPA promulgates a rule which will have a significant economic impact on a substantial number of small entities (as the MSAT2 fuel provisions do). EPA complied with all of these requirements. EPA conducted outreach to small entities and convened an SBAR Panel to obtain advice and recommendations of representatives of the small refiner industry. Section 609(b) requires that an SBAR Panel be convened before EPA publishes a notice of proposed rulemaking, and this Panel was timely convened. Section 609(b)(4) further requires the panel to "review any material the agency has prepared in connection with this chapter, including any draft proposed rule". This provision does not contemplate that the Panel have before it every detail of a proposed rule, given that the Panel's deliberations occur pre-proposal. EPA provided the SBAR Panel with the material required by section 609(b)(4), and also complied with the requirements of section 603 by preparing and publishing an initial regulatory flexibility analysis with the notice of proposed rulemaking. Furthermore, EPA considered the SBAR Panel recommendations carefully, and proposed many of them as part of the proposed rule (see generally 71 FR 15924-926). Indeed, EPA decided to adopt many of the recommendations as provisions in the final rule, including separate lead time for compliance with the 0.62 vol% annual average benzene standard, extended opportunities to generate early credits for the ABT program, as well as various hardship provisions to accommodate situations where individual refiners (both small and non-small) incur significant economic hardship after making best efforts to comply.

EPA also complied fully with the requirements of section 604 of SBREFA, preparing a final regulatory flexibility analysis (found in chapter 14 of the RIA) which, among other things, describes small refiner entities to which the rule applies, estimates their compliance burdens, and describes steps EPA has taken to minimize significant impact of the rule on small refiners. These steps, in addition to those described in the previous paragraph, include extended lead time for complying with the 1.3 vol% refinery maximum average, a small refiner-specific hardship provision for small refiners that are only able to comply with the 0.62 vol% annual average benzene requirement through purchase of credits and find themselves unable to do so, and a clarification of the circumstances under which the other hardship provisions in the final rule could apply.

The commenter maintains, in essence, that EPA cannot lawfully make changes to a rule between the convening of an SBAR Panel and publication of the final rule, or at least cannot lawfully do so without reconvening the Panel. The RFA contains no such requirements. The statute, in fact, contemplates that there will be changes between proposed and final rules, and states that EPA's only procedural requirement in such a case is to describe that change in the Final Regulatory Flexibility Analysis. See section 604 (a)(2) (each Final Regulatory Flexibility Analysis "shall contain a summary of the significant issues raised by the public comments in response to the initial regulatory flexibility analysis, a summary of the assessment of the agency of such issues, and a statement of any changes made in the proposed rule as a result of such comments"). EPA has fully complied with this requirement. Moreover, as explained above, there is no requirement that a Panel be presented with every provision an agency proposes, much less every provision ultimately adopted as a final rule. The RFA also contains no requirement that EPA reconvene a Panel between the proposed rulemaking and the final rulemaking.

Nor were the small refiners prejudiced by the procedures EPA used to adopt the maximum average requirement. EPA solicited comment on the option of adopting a 1.3 vol% maximum average (71 FR 15869, 15903) and received comment on the issue (including from small refiners). EPA thus adopted the maximum average requirement in compliance with procedures required by the RFA.

We have carefully evaluated the potential impacts on small refiners of meeting the 1.3 vol% maximum average standard (as well as the 0.62 vol% annual average standard). As explained in detail in chapter 14 of the RIA, we believe that it is both technically and economically feasible for small refiners to meet these standards. Indeed, there are compliance options for small refiners that are less costly than those we used for our cost estimates (see RIA section 9.3). The rule also accommodates circumstances of small refiners by including four extra years of lead time to comply with the maximum average standard (in keeping with our discussion at 71 FR 15877-78 cited by the commenter explaining why additional lead time is often needed for small refiners to comply with fuel standards). We have also added provisions to the general hardship provision at section 80.1335(c)(2), and clarified in the preamble to the final rule (section VI.A.3.b), that an individual refiner which demonstrates that it would incur significant hardship in complying with the maximum average standard may obtain one or more waivers of the standard's compliance date. We thus do not agree with the comments that the maximum average requirement is infeasible for small refiners and that the inclusion of the provision will undermine conclusion's about the rule's effect on fuel supply, or that the standard should be more lenient or not apply at all to small refiners.

We also disagree with the suggestion that small refiners be permitted to comply with the maximum average standard through use of PADD-specific credits. Geographic restrictions on credit use can prove to be very problematic. PADD restricted trading would necessitate that we set different standards in different PADDs, due to the different level of benzene reductions achievable considering cost and other factors in those PADDs. The annual average standard would, by necessity, have to be less stringent in some PADDs than the 0.62 vol% annual average standard that we are setting. This would also reduce the liquidity of the credit trading market, and thus drive up the costs of the program. We do not see this step as necessary given our analysis showing that the maximum average standard is feasible at reasonable cost for all refiners, including small refiners.

We believe that setting a nationwide standard with nationwide credit trading (to meet the 0.62 vol% annual average benzene standard) will meet the environmental goals of the program as well as the needs of refiners. We believe that even with a maximum average standard, the combination of provisions that we are finalizing will minimize the likelihood of extreme hardship for small refiners. As discussed earlier, we are finalizing several significant relief provisions that apply specifically to small refiners, namely four years of additional lead-time to meet the 1.3 vol% maximum average (until July 1, 2016). Further, the hardship provisions that we are finalizing are available to all refiners, and these provisions could apply to situations that the commenters identified may still occur. Please see section 4.1.1.4 of this Summary and Analysis document for a greater discussion on the 1.3 vol% maximum average.

4.9.1.5 Small Refiner Criteria

What Commenters Said:

We received comments regarding the criteria to qualify for small refiner status. The commenters stated that they believe that EPA should consider expanding the criteria to allow other refiners that would not otherwise qualify as small refiners to do so.

The commenters stated that many refineries located in PADD 5, including Alaska and Hawaii, are close in size to small refiners located in PADD 4. The commenters stated that they believe refineries in these western PADDs also face geographic challenges in contracting labor and professional services. The commenters further stated that refiners in these regions possess many of the same limitations and challenges that EPA has identified with small refineries, and they thus believe the rule needs to change to reflect this. The commenters stated that they believe that allowing additional time for non-small refineries to comply with the proposed benzene standard would help to level the competitive playing field.

Other commenters stated that they believe that EPA should abandon the criteria required to small refiner qualification criteria that were proposed (and have been used in prior fuels programs), and instead look to the definitions given in recent Congressional programs. The commenters stated that they believe that EPA's criteria of 1,500 or less employees and crude capacity limit of 155,000 barrels per calendar day (bpcd) are not adequate for determining which companies should receive regulatory flexibility. The Congressional programs that the commenters cited were the American Jobs Creation Act of 2004 (Jobs Act) and the Energy Policy Act of 2005 (Energy Act), both of which contained small refiner or refinery definitions that differ from EPA's criteria. The Jobs Act defines a small refiner as a refiner with a maximum of 1,500 employees in refinery operations only and a crude capacity limit of 205,000 bpcd, while the Energy Act's defines a small *refinery* as a refinery with a crude capacity limit of 75,000 bpcd. The commenters stated that they believe that EPA should use one of these definitions to determine which companies qualify as small.

One commenter specifically noted that it believes that the Small Business Administration's (SBA) definition, which EPA's small refiner criteria are largely based on, is intended to give preferences to small businesses under various government programs and was not written with any specific consideration of the refinery industry. The commenter stated that it believes that using employee count ignores the reality that some refiners are small within the industry but have an employee count swelled by employees in operations unrelated to refining. The commenter further noted that it believes that employee count does not measure of the relative size, financial strength, or the resources available to the company for regulatory compliance. Rather, the commenter stated that it believes that refining capacity is a more accurate and equitable measure of the "smallness" of a refiner—such as the definition provided in the Energy Act. The commenter thus proposed that the rule should define small refiner as: (1) no more than 1,500 employees engaged in refinery operations and no more than 155,000 bpcd crude oil capacity on a company-wide basis; or (2) no more than 155,000 bpcd crude oil capacity on a company-wide basis. The commenter also stated that the rule could, alternatively, extend additional compliance time to each "small refinery", defined as one with a crude oil capacity of no more than 100,000 bpcd.

Another commenter suggested that in the final rulemaking, EPA should use the Energy Act small refinery definition to eliminate "confusion and inequities." The commenter further stated that it believes that the definition should be based on the relative size of the physical plant (i.e., the amount of crude oil the refinery can process). The commenter also stated that EPA could alternatively use the small refiner definition from the Jobs Act.

Letters:
Giant Industries, Inc. OAR-2005-0036-0831
Sinclair Oil Corporation, Flying J. Inc., Suncor Energy (U.S.A.) Inc., and Tesoro Corporation OAR-2005-0036-0989
United Refining Company OAR-2005-0036-0827
United States Senator Michael Enzi, et al. OAR-2005-0036

Our Response:

EPA's small refiner criteria are largely based on the Small Business Administration (SBA) definition of a small refiner. The small business employee criteria were established for SBA's small business definition (per 13 CFR 121.201) to set apart those companies which are most likely to be at an inherent economic disadvantage relative to larger businesses. This definition must also be used during the Small Business Regulatory Enforcement Fairness Act (SBREFA) Panel process to determine which companies are considered small businesses. Under this process, EPA is required to focus consideration on small businesses and evaluate the burdens that a proposed rule would impose, and potential mechanisms to relieve burdens where appropriate. SBREFA and the Regulatory Flexibility Act require agencies to perform this assessment prior to each significant rulemaking that has a significant impact on a substantial number of small businesses. In keeping with the intent of SBREFA, EPA's overall approach in regulations establishing broadly applicable fuel standards has been to limit the small refiner relief provisions to the subset of refiners that are likely to be seriously economically challenged as a result of new regulations due to their size.

The Energy Policy Act of 2005 (EPAct) and the American Jobs Creation Act of 2004 (Jobs Act) both use definitions that are different from the SBA definition, and from the criteria EPA is adopting in this rule. The EPAct focuses on refinery size rather than company size, while the Jobs Act focuses on refinery-only employees rather than employees company-wide. The EPAct's definition is that a small *refinery* is one that produces no more than 75,000 bpcd. The Jobs Act definition states that a small refiner is one that produces no more than 205,000 barrels bpcd and employs no more than 1,500 employees in its refinery operations alone. Under programs subject to the EPAct and Jobs Act definitions, relief would be granted to refineries that are owned by larger companies, or companies that have additional sources of revenue (indicated by more employees and/or refining capacity), and also refineries owned by foreign governments. These definitions do not focus as directly on refiners which, due to their size, could incur serious adverse economic impact from fuel regulations; and EPA consequently is not adopting either of them in this rule.

It is true that the EPAct definition is applicable to the Renewable Fuels Program under section 211(o) of the Clean Air Act, but by its terms it does not apply to the MSAT program (which implements different statutory provisions). Therefore, for the Renewable Fuels Standard proposal (71 FR 55552, September 22, 2006), EPA proposed to apply the 75,000 bpcd small refinery definition. However, even here, because it was appropriate under the facts, EPA also proposed to apply the small refiner criteria from our previous fuel regulations as part of the RFS program.

We note that the small refiner provisions act to delay obligations to comply with fuel standards and do not act as a complete exemption from such requirements. In addition, the small refiner provisions represent one option in which requirements can be delayed under this program. The general hardship provisions (as discussed further in section VI.A.3.b) are available to all refiners, regardless of whether or not they meet the small refiner criteria. Under these hardship provisions, a refiner that can demonstrate financial and/or technical hardship in complying with the requirements of the regulation may apply under the general hardship provisions. Based on a case-by-case determination, EPA can than grant hardship relief which can act to delay requirements in a manner similar to the small refiner definition.

With regard to the comments on the small refiners' difficulty in meeting the 1.3 vol% refinery maximum average, we do understand the commenters' concerns. However, geographic restrictions on credit use can prove to be very problematic. We believe that, given the national trading of credits to meet the 0.62 vol% annual average benzene standard, neither the goals of refiners nor environmental goals could be met with such a program. We believe that even with a maximum average standard, the combination of provisions that we are finalizing will minimize the likelihood of extreme hardship for small refiners. As discussed earlier, we are finalizing several significant relief provisions that apply specifically to small refiners, namely four years of additional lead-time to meet the 1.3 vol% maximum average (until July 1, 2016). Further, the hardship provisions that we are finalizing are available to all refiners, and these provisions could apply to situations that the commenters identified may still occur.

4.9.1.6 Other

What Commenters Said:

Caribbean Petroleum Corporation and U.S. Oil and Refining Company both commented that they believe that the final rule should allow all refinery restarts the opportunity to participate as small refiners if they meet all requirements other than an ownership or operating status on a given date.

Caribbean and U.S. Oil also both commented that they believe that the rule should encourage refinery capacity increases (and further, any new rulemaking should do that when possible).

<u>Letters:</u>

Caribbean Petroleum Corporation	OAR-2005-0036-1010
U.S. Oil & Refining Company	OAR-2005-0036-0992

Our Response:

Our intent has been, and continues to be, limiting the small refiner relief provisions to the small subset of refiners that are likely to be seriously economically challenged as a result of the new regulations. Similar to earlier fuel rules, we are finalizing a provision that a refiner that restarts a refinery in the future is eligible for small refiner status to account for refineries that may have been temporarily shut down during the baseline year(s) but would otherwise have met the criteria. In such cases, we will judge eligibility under the employment and crude oil capacity criteria based on the most recent 12 consecutive months before the application, unless we conclude from data provided by the refiner that another period of time is more appropriate. However, unlike past fuel rules, this will be limited to a company that owned the refinery at the time that it was shut down. New purchasers will not be eligible for small refiner status. We assume that new owners that purchase a refinery after December 31, 2005 do so with full knowledge of the regulation. Given that they have the resources available to purchase the refinery assets, they are not in an economic hardship situation. Therefore, simply put, they can and should include compliance planning as part of their purchase decision. Companies with refineries built after January 1, 2005 will also not be eligible for the small refiner hardship provisions, again for the reasons given above.

In response to the comments regarding encouraging refinery capacity increases, as in past fuels programs, approved small refiners that grow by normal business practices will not lose their small refiner status for the MSAT2 program. This was discussed during the Small Business Regulatory Enforcement Act (SBREFA) Panel process. We agreed then, as we do now, that small refiner growth by normal business practice should not be discouraged by our regulations.

4.9.2 Other Hardship Provisions

What Commenters Said:

The Municipality of Anchorage, Department of Health and Human Services commented that it fears that credits and accommodation for economic hardship included in the proposed rule may allow benzene concentrations to remain unchanged in Alaska fuel. The commenter stated that it believes that the modest volume of fuel refined in Alaska may lead to claims of economic hardship by local refiners. The commenter noted that, since there is no market for extracted benzene in Alaska, the cost of shipping benzene out of the state may be more costly than potentially expensive refinery modifications. The commenter stated that it would be very disappointing if credits from refineries outside the state were used to support the continuation of current gasoline formulations. The commenter noted that Canadian regulations employ a per-gallon-cap limitation on benzene content with a lower averaging standard; and the commenter recommended that a similar provision be included in the rule to ensure that some reduction in benzene content is accomplished in small markets.

<u>Letters:</u>

Municipality of Anchorage, Department of Health and Human Services OAR-2005-0036-0976

Our Response:

Based on our refinery-by-refinery modeling, we believe that the 0.62 vol% annual average standard will provide a strong incentive for benzene reductions nationwide, including Alaska. In order to provide greater assurance that the modeled reductions occur, we are also finalizing a 1.3 vol% maximum average standard that will preclude refineries from remaining above that level for their actual production. While there are provisions for small refiner relief and hardship relief for any size refiner, these may only serve to delay application of the standard, not waive it indefinitely.

4.10 Western Refiner Issues

What Commenters Said:

We received comments from a group of refiners in the Rocky Mountain and Pacific Northwest regions (Petroleum Districts for Defense (PADDs) 4 and 5, respectively). These refiners commented that they believe that refiners in PADDs 4 and 5 will face compliance challenges with the proposed rule that are considerably more significant than refineries would face elsewhere in the county, as the current gasoline benzene levels for refiners in these areas are well above the national average of 0.97 vol%. The refiners stated that they believe that facilities in their region face the greatest compliance difficulty under the proposed regulation. The commenters further stated they believe that the impact of the regulation is even more challenging for small and independent refiners who have limited averaging options and whose refining operations are concentrated in PADDs 4 and 5.

The commenters stated that they believe other major regulations, along with significant capacity expansions and other major refinery projects, all compete with each other for funding and other resources, and they encourage EPA to sequence the requirements for benzene control relative to these other regulations would be beneficial. They also point to EPA analysis in the proposal showing that refiners in PADDs 4 and 5 will experience the highest compliance costs. The commenters also state that the rule favors large multi-refinery refiners over small and independent refiners because the ABT program’s provision for intra-company trading is of more use the more refineries a company own.

In general, the commenters believe that refiners in these areas should receive the same 4-year delay in the benzene requirements as small refiners. The also suggested a specific provisions where refineries in these PADDs be permitted to delay compliance with the 0.62 vol% benzene standard until January 1, 2015 (similar to the small refiner program start date) if they opted to comply with a maximum average benzene standard of 1.3 vol% on a permanent basis. If EPA adopted this approach, the commenters also suggested that refiners with more than one refinery in either PADD have the flexibility to meet the 1.3 vol% annual average gasoline benzene standard across the PADD if the facilities are located not more than 100 miles apart. The commenters stated that they believe this option would assure that bona fide gasoline benzene reductions will be made in the regions where average levels are the highest.

Letters:
Sinclair Oil Corporation, Flying J. Inc., Suncor Energy (U.S.A.) Inc., and Tesoro Corporation OAR-2005-0036-0989

Our Response:

We have carefully assessed the comments from this group of refiners. Our analysis confirms that refineries in PADDs 4 and 5 tend to have higher benzene levels than refineries in other parts of the country. Our analysis also shows that the costs for compliance will likely be greater for refineries in PADDs 4 and 5 than for other refineries. We recognized this diversity in benzene levels across the country in the design of the program by including a nationwide ABT program with no geographic restrictions. We also considered refineries in all parts of the country in assessing the necessary lead time for compliance.

Overall, we considered characteristics of refineries in the western part of the country, as well as all other refineries, as a part of our analyses supporting the proposed rule, and these characteristics continue to be included in our final rule analyses. We continue to believe that this program very effectively balances the concerns of a wide range of stakeholders in all parts of the country, including this group of refiners. The nationwide ABT program is designed to allow refiners to, in effect, phase in compliance with the 0.62 vol% average standard by generating early credits through partial reductions and then use those credits to postpone full compliance. Refiners can also purchase credits for the same purpose. The additional 18 months that we are providing for compliance with the 1.3 vol% maximum average standard is also intended to allow full use of the credit program through that date. Our analyses indicate that the average standard of 0.62 vol% and the 1.3 vol% maximum average standard, in the context of the nationwide ABT program, will be achievable by all refineries by the respective compliance dates. (See also the discussion of leadtime in section 4.3 above.) In the event that refineries still face extreme hardship situations as defined in the rule, EPA can provide compliance relief on a case-by-case basis.

Regarding the commenters' proposal that refiners in their region be treated as small refiners under this program, we address the issues of expanding the criteria for small refiner status in section 4.9 above.