



Gasoline Sulfur Rule Questions and Answers

The following are responses to questions received by the Environmental Protection Agency (EPA) concerning the manner in which the EPA intends to implement and assure compliance with the gasoline sulfur regulations at 40 CFR Part 80. This document was prepared by EPA's Office of Air and Radiation, Office of Transportation and Air Quality, and the Office of Enforcement and Compliance Assurance, Office of Regulatory Enforcement.

Regulated parties may use this document to aid in achieving compliance with the gasoline sulfur regulations. However, this document does not in any way alter the requirements of these regulations. While the answers provided in this document represent the Agency's interpretation and general plans for implementation of the regulations at this time, some of the responses may change as additional information becomes available or as the Agency further considers certain issues.

This guidance document does not establish or change legal rights or obligations. It does not establish binding rules or requirements and is not fully determinative of the issues addressed. Agency decisions in any particular case will be made applying the law and regulations on the basis of specific facts and actual action.

While we have attempted to include answers to all questions received, the necessity for policy decisions and/or resource constraints may have prevented the inclusion of certain questions. Questions not answered in this document will be answered in a subsequent document. The Agency intends to provide additional responses as expeditiously as possible. Questions that merely require a justification of the regulations, or that have previously been answered or discussed in the preamble to the regulations have been omitted.

STANDARDS AND COMPLIANCE

1. **Question:** Were some words left out of § 80.195(a)(1) in the final rule published in the *Federal Register*?

Answer: Yes. Some words were inadvertently left out of § 80.195(a)(1) when the final rule was published in the *Federal Register* on February 10, 2000. The correct introductory language of § 80.195(a)(1) is: "The gasoline sulfur standards for refiners and importers, excluding gasoline produced by small refiners subject to the standards at § 80.240, and gasoline designated as GPA gasoline under § 80.219(a), are as follows:" On February 28, 2000, the

Federal Register Office published a notice to correct this error.

2. **Question:** The preamble at 65 FR 6819 states: "Many of the requirements do not become applicable until the beginning of the sulfur control program on October 1, 2003, when all refiners are required to meet the sulfur standards." Is this date correct? Although the proposal listed October 1, 2003, as the effective date for the sulfur cap at the refinery, doesn't the final rule specify January 1, 2004?

Answer: The effective date of the sulfur standards was changed from the date proposed in the Notice of Proposed Rulemaking (NPRM). In the final rule, the corporate pool annual average standards and the refinery and importer per-gallon cap standards are effective beginning January 1, 2004. (The refinery and importer annual average standards are effective beginning January 1, 2005.) The reference in the preamble at 65 FR 6819 regarding the date that refiners are required to meet the sulfur standards should be January 1, 2004, instead of October 1, 2003.

3. **Question:** In the NPRM, the sulfur standards were expressed without decimal places, but the final rule provides that the standards are expressed with two decimal places (§§ 80.195, 205). Why did EPA include this change?

Answer: EPA included the decimal places to ensure that the sulfur standards are not exceeded by rounding down actual average sulfur levels. We do not believe reporting the average sulfur level to two decimals creates any additional burden as the averaging calculation will yield this result to any number of decimal places. Although the decimals were not included in § 80.216(a)(1)(i) for the geographic phase-in area (GPA) standard, EPA intends to revise this provision to include the decimals in a future rulemaking.

4. **Question:** Section 80.205(e) (2) of the final rule states: "No refiner or importer may have a compliance deficit in any year after 2010. Any deficit that exists in 2010 must be made up in 2011". We could interpret the end of the credit program as being the 2011 compliance year. There could be many expensive decisions made affecting gasoline supply in the U.S. in the 4th quarter of each year in 2012 and beyond for the sake of several ppm sulfur. Why is the refiner flexibility for compliance with the 30 ppm average using credits eliminated beyond 2011?

Answer: The provisions in § 80.205(e) which allow a deficit to be carried over to the following year are included in the regulations to provide additional flexibility for parties in the early years of the sulfur program in the event of an unexpected shutdown or inability to obtain credits. *See* 65 FR 6764. Refiners and importers will continue to be able to purchase credits to achieve compliance with the 30 ppm average in 2011 and beyond in the event that unexpected exceedences of the standards occur. However, after the 2010 averaging period, refiners and importers must demonstrate compliance with the standard for each averaging period (i.e., if the refiner's or importer's actual annual average exceeds the standard in the 2011 averaging period,

or any averaging period thereafter, the refiner or importer must obtain sufficient credits to demonstrate compliance for that averaging period). The refiner or importer will have until the last day of February of the following year (when the annual averaging report is due) to obtain the necessary credits.

5. **Question:** Please verify that if a refiner is also a gasoline importer, the refiner's corporate pool must include the imported gasoline for compliance with the corporate pool average standard for 2004 & 2005.

Answer: For purposes of calculating compliance with the corporate pool annual average standards at § 80.195(a)(1), a refiner who is also an importer must include in its pool the volume of gasoline production from all refineries and the volume of gasoline imported during the averaging period. *See* § 80.195(c)(1).

6. **Question:** If a company that qualifies as a small refiner is also an importer, would the company only comply with the corporate pool average standards for its volume of imported gasoline?

Answer: The company's small refinery would not be subject to the corporate pool average standards. *See* § 80.195(c)(4). As a result, the company would only need to demonstrate compliance with the corporate pool average standards for its imported gasoline.

7. **Question:** The preamble states that, in 2005, each refinery may only use credits to achieve the 30 ppm standard after the refiner has demonstrated compliance with the 90 ppm corporate pool average for all refineries. The refiner must meet the corporate pool average standard on actual sulfur levels or through a trade for allotments. At this point, each of the refiner's refineries must obtain sulfur credits to bring the refinery's sulfur average down to 30 ppm. Please explain how this works, particularly where a refiner has one or more refineries that have an average of 30 ppm or less.

Answer: The regulations require a refiner or importer, in 2005, to demonstrate compliance with the 90 ppm corporate pool average standard by calculating its actual corporate average sulfur level using the actual sulfur levels of each batch of gasoline and then applying allotments, as necessary, to meet the 90 ppm standard. Credits may not be used to achieve compliance with the corporate pool average standard. *See* § 80.315(c)(4). The regulations also require a refiner for each refinery, or an importer, to demonstrate compliance with the refinery or importer average standard by calculating the actual refinery or importer sulfur level using the actual sulfur levels of each batch of its gasoline, and applying credits and/or allotments, as necessary, to meet the 30 ppm standard. The regulations identify the corporate average and refinery average standards as two separate standards, and do not require refiners to demonstrate compliance with one or the other standard first.

In 2005 only, refiners and importers may use credits and/or allotments to demonstrate

compliance with the refinery or importer average standard. *See* § 80.195(b)(4). These credits or allotments may be obtained from any source. A refiner with more than one refinery may use credits generated by a refinery with an average sulfur level below 30 ppm towards meeting the refinery average standard at one of its other refineries. Alternatively, the refinery may choose to bank or sell the credits, as permitted by the regulations. In 2005, the same pool of allotments used to demonstrate compliance with the corporate pool standard may be used by a refinery in the pool toward its demonstration of compliance with the refinery average standard, or some of the allotments may be used by one refinery and the remainder used by another refinery or refineries in the pool. For example, a refiner with two refineries who obtains 30 allotments to achieve compliance with the corporate pool standard may apply all 30 allotments to one refinery, or some of the allotments to each of the two refineries (for example: 15 allotments to each refinery; 20 allotments to one refinery and 10 to the other; etc.). We intend clarify the requirements regarding how allotments may be used to demonstrate compliance with the corporate pool average standard and the refinery average standard in 2005 in a future rulemaking.

As indicated in the Question, the preamble states that, in 2005, a refiner first must demonstrate compliance with the corporate pool average standard of 90 ppm, and then demonstrate compliance with the refinery average standard using a maximum of 90 ppm as the average sulfur level for each refinery, and applying credits to bring each refinery's average down to 30 ppm. *See* 65 FR 6760. However, this discussion in the preamble is not consistent with the manner in which compliance is demonstrated under the regulations; i.e., compliance with the corporate pool average standards and with the refinery average standards is demonstrated separately, and refiners are required to use actual sulfur levels in computing the refinery average, as compared to using presumed levels of 90 ppm for each refinery after demonstrating compliance with the corporate pool average standard. Therefore, we are withdrawing this preamble discussion as guidance for interpreting the regulations on this particular issue. The regulations do not impose any particular priority on compliance with the corporate average and the refinery average standards in 2005. Contrary to the statements in the preamble referenced above, refiners need not first demonstrate compliance with the corporate pool average standard; rather, each standard is independent of the other and must be met as such.

8. **Question:** Please clarify how § 80.205(f) is to be applied.

Answer: The regulations provide that a refiner or importer must meet the corporate pool average standards under § 80.195 if their gasoline production or volume of imported gasoline is comprised of less than 50 percent of gasoline designated as GPA gasoline *See* § 80.216(f). As discussed in the preamble, we intended refiners and importers subject to the corporate pool average standard who produce some GPA gasoline to use the same compliance process as other refiners and importers subject to the corporate pool average standards in 2004-2005. *See* 65 FR 6763. However, as described in the answer to Question 7 above, the preamble discussion regarding compliance with the refinery average and corporate pool average standards in 2005 is inconsistent with the manner in which compliance with these standards is demonstrated in the regulations. Therefore, we are also withdrawing the statements in the preamble

specifically describing compliance with the corporate pool average and refinery average standards for such refiners and importers. Thus, as for all other refiners and importers, such refiners and importers must demonstrate compliance with both average standards (as calculated under 80.205), but are not required to demonstrate compliance with the corporate pool average standard first. We intend to revise the regulations at 80.205(f) to be consistent with the manner with which the standards are described in 80.195 and with other relevant provisions of the final rule.

9. **Question:** Do refiners have to include in their calculations of compliance with the corporate pool average standard all refineries owned by subsidiaries and refineries owned by joint venture partners?

Answer: The regulations state that the corporate pool average standards apply to the refiner's gasoline production from all of its refineries in a calendar year. *See* § 80.195(c)(1). Joint ventures, where two or more parties collectively own and operate a refinery, are treated as a separate refiner subject to a separate corporate pool average standard. However, the regulations allow one partner in a joint venture to include the joint venture's refineries in its corporate pool for purposes of calculating compliance with the corporate pool average standard. If one partner does this, the joint venture will be considered to be in compliance with the corporate average standard, where the partner that counts the joint venture refineries meets the corporate average standard. *See* § 80.195(c)(5). For any joint venture refineries not included in a partner's compliance calculations, the joint venture must demonstrate compliance with the corporate pool average standard. Thus, partners in a joint venture have the flexibility under the regulations to comply with the corporate pool average as a joint venture, or to count the joint venture refineries in either partner's compliance calculations.

The corporate pool average standard applies to all refineries owned by a refiner, which EPA interprets to include refineries owned by the refiner's wholly-owned subsidiaries. *See* 65 FR at 6755. Where a refiner partially owns a refinery, that refinery is not considered part of the refiner's corporate pool average. Where two or more parties collectively own and operate a refinery, that is considered a joint venture, and as discussed above, one partner of the joint venture may include the refinery in its corporate pool average. *See* § 80.195(c)(5).

10. **Question:** What types of business arrangements does EPA consider to be joint ventures under § 80.195 and other provisions of the sulfur program? How are other types of shared refiner ownership to be treated under the regulations?

Answer: EPA considers a joint venture to be a situation in which two or more parties collectively own and operate one or more refineries. *See* 65 FR at 6755. This definition is intended to encompass a broad range of business arrangements where two or more entities share ownership of a refinery. Thus, EPA expects that most cases of shared refinery ownership will be considered joint ventures under the regulations. For situations where a refinery is owned by more than one party, but not all parties participate in the refinery's operation, the refinery is considered a separate entity, and the refiner of that refinery is the business entity consisting of the

multiple owners. However, we believe that, in this case, one of the owners should be allowed to include the refinery in its corporate pool as the regulations allow in joint venture situations. As a result, we intend to make this change in a future rulemaking.

11. **Question:** May a limited liability company be considered a joint venture for purposes of the provisions under § 80.195(c)(5)?

Answer: Under § 80.195(c)(5), a joint venture is one in which two or more parties collectively own and operate one or more refineries. Any joint ownership arrangement that meets this criteria, including a limited liability arrangement, will be considered a joint venture for purposes of compliance with the corporate pool standards.

12. **Question:** Please clarify whether oxygenates blended into either conventional gasoline or Reformulated Blendstock for Oxygenate Blending (RBOB) downstream of the refinery need to be included in sulfur compliance calculations.

Answer: Section 80.205(c) provides that a refiner or importer may include oxygenates added downstream from the refinery or import facility if the requirements under § 80.69(a) or § 80.101(d)(4)(ii) of the RFG/CG regulations are met. Therefore, a refiner or importer may include, but is not required to include, oxygenates blended downstream in sulfur compliance calculations.

GEOGRAPHIC PHASE-IN AREA

1. **Question:** It is our understanding that, if a portion of the gasoline produced by a refinery located within the GPA is sold outside of the United States, that gasoline is not subject to the sulfur standards and it only has to meet the standards of the country to which it is exported. Is this correct?

Answer: Gasoline that is exported for sale outside the United States is not subject to the requirements of the gasoline sulfur rule, including gasoline produced by a refiner located within the GPA. *See* § 80.200(c).

2. **Question:** Footnote b of Table IV.C.-2 of the preamble is inconsistent with the regulations at § 80.216(f). The regulations clearly state that the corporate pool average standards do not apply if a refiner's production volume is mostly GPA gasoline. If the refiner/importer volume is less than 50 percent GPA gasoline, then the corporate pool average standard applies.

Answer: The regulations at § 80.216(f) are correct. There was an error in footnote b of Table IV.C.-2 of the preamble released on 12/21/00, which subsequently was corrected in the final rule published in the *Federal Register* on February 10, 2000.

3. **Question:** Please clarify how GPA gasoline should be treated for purposes of complying with the corporate pool annual average standards. The preamble to the final rule says that refiners and importers who market most of their gasoline outside of the GPA (and, therefore, the corporate pool average standard applies) must then include GPA gasoline in the calculation of the corporate pool average. The regulations at § 80.216(f)(2) say that if the refiner's or importer's volume is less than 50 percent GPA gasoline, then the corporate pool average standard applies and all volume must be included (presumably including GPA gasoline).

Answer: If a refiner's or importer's gasoline volume is comprised of less than 50 percent GPA gasoline, the corporate pool average standards apply, and all of the refiner's gasoline production and/or all of the importer's gasoline imports, including GPA gasoline, must be included for purposes of calculating compliance with the corporate pool annual average standards. We intend to add language to § 80.216(f)(2) in a future rulemaking to clarify the gasoline production that is subject to the corporate pool annual average standards under this provision. *See* 65 FR 6757.

4. **Question:** In determining whether the corporate pool average standard applies to a refiner who produces GPA gasoline under § 80.216(f), may the refiner include gasoline production from refineries owned by its subsidiaries or by joint ventures in which it is a partner?

Answer: In calculating the percentage of a refiner's production that is designated as GPA gasoline, EPA interprets the regulations to require the refiner to count gasoline produced by refineries owned by wholly owned subsidiaries. These are the entities that must be included in the calculations of compliance with the corporate pool average. Refineries that the refiner partially owns, including refineries owned by joint ventures and other business arrangements through which it shares ownership of a refinery, are considered separate entities under the regulations, owned by the business entity comprised of the multiple owners. Therefore, EPA will consider such business entities as separate refiners for purposes of determining whether compliance with the corporate pool standards applies under § 80.216(f). EPA will not consider these entities to be part of the production of one of the owners. However, once it is determined under § 80.216(f) that a GPA refiner is required to comply with the corporate pool standards, the party may include a joint venture refinery in its pool for purposes of demonstrating compliance with the corporate pool standards (assuming the joint venture refinery is also required to comply with the corporate pool standards).

5. **Question:** What specification standard does a GPA refinery use to ship outside a designated GPA area?

Answer: Gasoline produced by a refinery located within the GPA, but intended for use outside the GPA, must meet the standards and requirements under the sulfur regulations for non-GPA gasoline. Gasoline intended for use within the GPA must be designated as GPA gasoline by the refiner or importer, and it is prohibited from being distributed for use outside the GPA. Product transfer documents accompanying GPA gasoline must identify the gasoline as being

GPA gasoline and include a statement that the gasoline may not be distributed or sold for use outside the GPA.

6. **Question:** Under the GPA program, a refiner must submit an application for GPA standards by 12/31/2000. If a refiner who has not historically supplied the GPA wishes to supply gasoline to the GPA area some time after 12/31/2000, can the GPA application be submitted at that time?

Answer: The GPA provisions provide for less stringent standards during the early years of the sulfur program for gasoline intended for sale in the GPA. As discussed in the preamble, the GPA provisions are intended to provide relief for those refiners who are located in or near the GPA and who supply that area. See 65 FR 6756-57. We believe that those refiners will have sufficient time under the application deadline in the regulations to apply for GPA gasoline standards. As a result, refiners may not apply for GPA standards after that date. Note, however, that a refiner who does not have an approved GPA standard may supply gasoline to the GPA at any time, since non-GPA gasoline is not prohibited from being sold in the GPA.

SMALL REFINERS

1. **Question:** Section 80.225(a)(3) says that, to qualify for small refiner status, the average crude capacity of the refiner must be less than or equal to 155,000 bpcd for 1998. However, the preamble says "for 1999." Is there is an inconsistency here?

Answer: Yes. There was an inconsistency between in the preamble and § 80.225(a)(3) regarding the crude oil capacity criteria for small refiners. This inconsistency was corrected in the final rule published in the *Federal Register* on February 10, 2000. The correct criteria is an average crude capacity less than or equal to 155,000 bpcd for 1998.

2. **Question:** Section 80.230(a)(1) says "Refiners of refineries built after January 1, 1999." This section should read, "Refiners with refineries built after January 1, 1999."

Answer: The regulatory language is clear that refiners who own refineries built after January 1, 1999, are not eligible for the small refiner hardship provisions. However, we agree that the suggested change would clarify the provision, and intend to make this clarification in a future rulemaking.

3. **Question:** Assume that a small refiner has a baseline of 100 ppm, its standard under § 80.240(a) would be 100 ppm. However, the corporate pool average for 2004 is 120 ppm and there is no individual refinery standard. As a result, the small refiner would be better off not to elect small refiner status until the year 2005. Is this possible?

Answer: The regulations provide that any refiner who wishes to participate in the small

refiner program must apply by December 31, 2000. Upon approval of the application, EPA will notify the refiner of each small refinery's applicable standard, baseline volume, and per-gallon cap standard. *See* § 80.235. EPA interprets the regulations to require approved small refinery standards to apply from the beginning of the small refiner program in 2004, and to be in effect until the end of the small refinery program in 2008, unless the refiner notifies EPA under § 80.230(b)(2) of an election to comply with the standards in § 80.195. As a result, a refiner who obtains small refiner status may not elect to have the small refinery standards become effective in 2005 rather than 2004. EPA also interprets the election under § 80.230(b)(2) to be a one time election. If a small refiner chooses to opt out of the small refiner program pursuant to § 80.230(b)(2) and comply with the standards in § 80.195, the refiner may not elect to have its small refinery standards apply in a subsequent averaging period.

4. **Question:** For purposes of establishing small refiner status, do refiners have to include in their calculation of number of employees and corporate crude capacity all refineries owned by subsidiaries and all refineries owned by joint venture partners?

Answer: The sulfur regulations define "small refiner" as a refiner who produces gasoline at a refinery by processing crude oil through refinery processing units, employed no more than 1,500 people in calendar year 1998, and had an average crude capacity for 1998 less than or equal to 155,000 barrels per calendar day (bpcd). *See* § 80.225(a)(1). The regulations state that, for purposes of determining the number of employees and corporate crude capacity, the refiner must include the employees and crude capacity of any subsidiary companies, any parent company, subsidiaries of the parent company, and any joint venture partners. EPA interprets this regulation to require refiners to include employees and crude capacity at any and all subsidiaries, as well as employees and crude capacity of any joint venture partners. *See* § 80.225(a)(2). EPA interprets a subsidiary of a company to mean any subsidiary in which the company has a 50 percent or greater ownership interest.

5. **Question:** In applying for small refiner status, does a refiner have to include in its average crude capacity in 1998 any capacity used under a leasing agreement at a refinery it does not own?

Answer: The regulations require a refiner applying for small refiner status to provide its total corporate crude capacity in its application. The definition of small refiner is limited to those refiners with average crude capacity in 1998 less than or equal to 155,000 barrels per calendar day (bpcd), and no more than 1,500 employees in 1998. In determining crude capacity, the regulations require refiners to include the crude capacity of any subsidiary companies, any parent company and subsidiaries of the parent company, and any joint venture partners. Other than these specific entities, the regulations do not specify which refineries must be included in the crude capacity calculation for small refiner status. *See* §§ 80.225 and 80.235.(a)(2)

The crude capacity limit was adopted to ensure that only truly small companies who need additional time to comply can qualify for small refiner status. Refiners who have relatively large crude capacity will likely be in a better position to finance and install desulfurization equipment

to meet the national standards in 2004, even if they employ less than 1,500 people. In addition, the crude capacity limit is intended to limit the potential environmental impacts of the small refiner standards, by ensuring that the volume of gasoline subject to such standards is not significant. *See* 65 FR 6767.

EPA interprets its regulations to require refiners applying for small refiner status to include only the crude capacity in 1998 at refineries it owned, including refineries owned by subsidiaries, parent companies and subsidiaries of the parent company, and partners in joint ventures. Thus, refiners are not required to include crude capacity used in 1998 pursuant to a lease agreement with another refiner in which it has no ownership stake. This approach is consistent with the purposes of the capacity limit. First, an agreement to lease crude capacity is not likely to significantly impact a refiner's ability to finance and install desulfurization equipment at its refineries. While such an agreement will have some value, we do not expect it will be sufficient to assist a refiner in generating capital to make refinery investments to reduce sulfur in time to meet the national standards in 2004.

In addition, this interpretation will not increase the volume of gasoline potentially subject to the small refiner standards. Small refiner standards apply based on the small refiner's baseline sulfur level and baseline volume. These values are calculated for each of the small refiner's refineries. *See* §§ 80.245 and 80.250. As described above, the crude capacity at a facility leased by a small refiner is not considered part of the refiner's capacity for purposes of small refiner status. Therefore, that facility is not considered one of the small refiner's refineries, and is not assigned a baseline sulfur level or volume under § 80.250. Thus, production at that refinery is subject to the national sulfur standards.

6. **Question:** The sulfur rule says that a small refiner must produce gasoline by processing crude oil through a refinery processing unit. Does our refinery meet that requirement if we produce gasoline by processing crude oil through a processing unit, but we sometimes finish creating our batches through the later addition of other blendstocks at the refinery? We add components such as ethanol or raffinate to create the qualities we want in the finished batch.

Answer: Under § 80.225(a), a small refiner is a refiner who processes crude oil through refinery processing units, employed an average of no more than 1,500 people during 1998, and had an average crude capacity less than or equal to 155,000 barrels per calendar day for 1998. In the situation described in this question, the refiner fits that part of the small refiner definition that requires the refiner to be one who processes crude oil through refinery processing units, since the refiner produces gasoline by processing crude oil. The fact that the refiner may also finish a batch through the later addition of other blendstocks does not affect its small refiner status. However, the volume of blendstocks used by the refiner should be excluded from the determination of crude capacity, unless the blendstocks have undergone substantial transformation through the refining process.

ALLOTMENTS AND CREDITS

1. **Question:** Should California gasoline be excluded from baseline calculations for purposes of generating early credits?

Answer: Yes. California gasoline as defined in § 80.375 should be excluded from 1997-1998 baseline calculations for purposes of generating early credits, and also for purposes of submitting a baseline under the small refiner, GPA or temporary hardship relief provisions. The sulfur regulations provide that California gasoline is not subject to any of the provisions of the sulfur program. *See* § 80.200. This includes the baseline application provisions at §§ 80.245 and 80.290, as well as the provisions for determining annual sulfur levels at § 80.205. The sulfur regulations also provide that the 1997-1998 sulfur baselines are based on the refiner's RFG/anti-dumping compliance data, as submitted to EPA in the RFG/anti-dumping reports. California gasoline is generally required to be excluded from these reports. *See also* EPA's "Guidance to Parties Submitting Gasoline Sulfur Baseline Applications" (EPA420-S-00-001, March 2000), which is posted on the Office of Transportation and Air Quality web site at: <http://www.epa.gov/otaq/tr2home.htm>.

2. **Question:** The baseline submission guidance is silent on the impact of refinery acquisitions and sales on a gasoline sulfur baseline. Please provide guidance on how a refinery sale or acquisition during 1997/1998 should be handled with regard to baseline establishment, and how a refinery sale/acquisition should be handled after 1998 and prior to submitting a baseline application (i.e, sale or acquisition during 1998-2000). If a refiner did not produce gasoline in 1997-1998 (for example, a recent start-up), how would that refiner establish a sulfur baseline for credit generation? Is there a process for resubmitting a baseline if a refinery is sold/acquired after a baseline has been approved?

Answer: We interpret the regulations to require a refinery's sulfur baseline to be calculated based on all of the gasoline produced by the refinery during 1997-1998, without regard to ownership. In the case of a refinery that changed ownership during 1997-1998, or after 1998, we expect that any data required to establish the sulfur baseline generated prior to the new owner's acquisition of the refinery will be available to the new owner for purposes of submitting a baseline application. If a refinery changes ownership after its baseline is approved, the new owner would need to submit a baseline application for the refinery under § 80.290. The new owner would indicate in the application that the refinery had received an approved baseline under prior ownership.

For a refinery that was not in operation in 1997-1998, we believe that sulfur data for at least 12 consecutive months should be required to establish a sulfur baseline for early credit generation. The baseline application for such a refinery should include data for the gasoline produced during each year the refinery was in operation after the refinery was reactivated. Where appropriate, the baseline for such refineries will be determined based on the annual average sulfur content for the most recent year of operation. We intend to modify the regulations to provide for this situation in a future rulemaking.

3. **Question:** If a refiner believes that certain data submitted in the 1997-1998 RFG/anti-dumping batch reports contains some inaccuracies (which would not have resulted in non-compliance), can or should such data be excluded from the data submitted to EPA for purposes of establishing a 1997-1998 sulfur baseline?

Answer: We believe that such a determination would depend on the refiner's specific concerns. We suggest that any refiner who has concerns about data quality consult with EPA before submitting a sulfur baseline application.

4. **Question:** Recently issued guidance specifies that GTAB must be excluded from the volume of gasoline for determining a sulfur baseline. Please explain why GTAB is to be excluded. Does this exclusion apply to both domestic importer-refiners and foreign refiners?

Answer: The recent EPA guidance on baseline submissions specifies that GTAB ("gasoline treated as blendstock") batch report data should not be included in baseline determinations for sulfur. See "Guidance to Parties Submitting Gasoline Sulfur Baseline Applications," March 2000. This guidance was intended primarily for domestic importer-refiners who use GTAB. The GTAB approach under the RFG program is designed to allow domestic importer-refiners to correct off-spec imported gasoline by conducting remedial blending before it leaves the importer-refiner's facility. In this situation, the GTAB is used by the party as a *blendstock* and blended with other components to bring the product to specifications. The regulations provide that only finished gasoline is to be included in the baseline determination. Therefore, GTAB batches should be excluded from baseline calculations by importer-refiners, as described above.

In the case of a foreign refiner, baselines are determined based on the volume and sulfur content of all of the finished gasoline produced at the foreign refinery that is imported into the U.S. See §§ 80.94(b) and 80.410(b). Gasoline is not designated as GTAB when it leaves the foreign refinery. It is not until the gasoline is imported into the U.S. that the product is designated as GTAB by the importer-refiner. As a result, a foreign refiner would not have any basis upon which to exclude from its baseline determination any gasoline produced by the foreign refinery that was imported into the U.S. in 1997-1998, including gasoline that was subsequently used by the importer-refiner as GTAB. Therefore, a foreign refiner should include in its baseline calculations all gasoline that was imported into the U.S. in 1997-1998, regardless of whether any of the gasoline was subsequently used by the importer-refiner as GTAB.

5. **Question:** If a foreign refiner registers and submits its sulfur baseline for purposes of generating credits in 2000, when can the foreign refiner begin to designate cargoes for credit generation?

Answer: Early credits generated by a foreign refiner who has an approved sulfur baseline will be based on all of the gasoline produced by the foreign refinery that is imported into the U.S. during the annual averaging period. Therefore, for the purpose of determining credits for the

2000 annual averaging period, all shipments of gasoline produced at a foreign refinery and exported to the U.S. from January 1, 2000, through December 31, 2000, may be included in calculating the refinery's annual average sulfur level. For credits generated in 2000, the foreign refiner will be required to submit a sulfur report by February 28, 2001, which includes data relating to the refinery's sulfur baseline, the sulfur content and volume of the gasoline exported to the U.S. by the refinery during the averaging period, and credits generated.

6. **Question:** The allotment program is very complex. The calculation of allotments and/or credits may be a critical factor in a refiner's compliance. What mechanisms will be adopted by EPA to avoid problems of refiner compliance due to misinterpretation and errors in calculations?

Answer: Although the allotment program appears complex, we believe that the equations provided in § 80.275 are straightforward and relatively easy to apply. We will, however, provide assistance to any company that is having difficulty applying these provisions.

7. **Question:** Why are credits and allotments expressed in ppm-gallons and not in ppm-barrels, since barrels or thousand barrels are the commercial units used by refiners?

Answer: Consistent with the requirements under the RFG program, § 80.195(a)(2) provides that, for purposes of sulfur compliance and reporting, volumes are expressed in gallons. Accordingly, credits and allotments are required to be calculated and reported in units of ppm-gallons. Although barrels may be the commercial units used by refiners, the conversion from barrels to gallons requires a simple calculation which should not impose an undue burden on regulated parties.

8. **Question:** The regulations at § 80.275(a)(2)(i) discount Type A sulfur allotments by 20 percent when the average sulfur content is ≤ 30 ppm, whereas the preamble states that allotments retain full value if the annual average sulfur level is ≤ 30 ppm. Similarly, § 80.275(a)(2)(ii) includes a 20 percent discount for Type A sulfur allotments. Which is correct, the regulations or the preamble?

Answer: There is an inconsistency between the regulations and the preamble regarding whether Type A sulfur allotments should be discounted when the refiner's average sulfur content is ≤ 30 ppm. The approach we intended to adopt is the one stated in the preamble, in which allotments retain full value if the annual average sulfur level is ≤ 30 ppm. *See* 65 FR 6759. We intend to correct the equations at § 80.275 in a future rulemaking.

9. **Question:** In the preamble, an example is given of a refinery generating allotments based on a 2003 average of 50 ppm and 20 ppm. Please demonstrate the credits and allotments generated for each refinery and under each scenario for 2003 in the table shown below to help clarify how credits and allotments are generated under various conditions.

| | Baseline | 2003a | 2003b | 2003c |
|------------|----------|-------|-------|-------|
| Refinery A | 25 | 35 | 25 | 20 |
| Refinery B | 50 | 50 | 25 | 40 |
| Refinery C | 100 | 50 | 25 | 80 |
| Refinery D | 300 | 50 | 25 | 240 |

Answer: The allotments and credits that would be generated in 2003 in the scenarios described are as follows (assume 1 gallon volume). (Note that we intend to modify §§ 80.274(a)(2)(i) and (ii) to delete the discount factor of 0.8 in these provisions - See Question 9 above.)

Refinery A (Baseline - 25 ppm):

- a) Average 35 ppm (§ 80.275(a)(2)(v)): $((25 - 35) \times 1) \times 0.8 = 0$ allotments
- b) Average 25 ppm (§ 80.275(a)(2)(iii)): $(25 - 25) \times 1 = 0$ allotments
- c) Average 20 ppm (§ 80.275(a)(2)(iii)): $(25 - 20) \times 1 = 5$ Type B allotments

Refinery B (Baseline - 50 ppm):

- a) Average 50 ppm (§ 80.275(a)(2)(v)): $((50 - 50) \times 1) \times 0.8 = 0$ allotments
- b) Average 25 ppm (§ 80.275(a)(2)(ii)): $(50 - 30) \times 1 = 20$ Type A allotments
 $(30 - 25) \times 1 = 5$ Type B allotments
- c) Average 40 ppm (§ 80.275(a)(2)(v)): $((50 - 40) \times 1) \times 0.8 = 8$ Type A allotments

Refinery C (Baseline - 100 ppm):

- a) Average 50 ppm (§ 80.275(a)(2)(v)): $((100 - 50) \times 1) \times 0.8 = 40$ Type A allotments
- b) Average 25 ppm (§ 80.275(a)(2)(ii)): $(100 - 30) \times 1 = 70$ Type A allotments
 $(30 - 25) \times 1 = 5$ Type B allotments
- c) Average 80 ppm (allotments/credits may not be generated under § 80.275(a)(2) if the refinery average is greater than 60 ppm; however, in this example, credits may be generated under § 80.305):
 $1 \times (100 - 80) = 20$ credits.

Refinery D (Baseline - 300 ppm):

- a) Average 50 ppm (§ 80.275(a)(2)(iv)): $(300 - 120) \times 1 = 180$ credits
 $((120 - 50) \times 1) \times 0.8 = 56$ Type A allotments
- b) Average 25 ppm (§ 80.275(a)(2)(i)): $(300 - 120) \times 1 = 180$ credits
 $1 \times 90 = 90$ Type A allotments
 $(30 - 25) \times 1 = 5$ Type B allotments
- c) Average 240 ppm (allotments/credits may not be generated under § 80.275(a)(2) if the refinery average is greater than 60 ppm; however, in this example, credits may be generated under § 80.305):
 $1 \times (300 - 240) = 60$ credits

10. **Question:** Between 2000 and 2003, a refinery can generate early sulfur credits, which would be reported to EPA, but the refinery would not report any deficit (i.e., if the refinery produced higher sulfur gasoline than its 1997-1998 baseline during 2000-2003). If the refinery's annual average sulfur level in 2000-2003 exceeds the refinery baseline, there is no violation of EPA regulations as long as all RFG and anti-dumping regulations are met. Are these statements correct?

Answer: These statements are correct since there is no sulfur standard prior to 2004. However, parties would be liable for any improper credits that are claimed.

11. **Question:** The preamble says: "Beginning July 1, 2000, certain requirements apply to parties that voluntarily opt for early sulfur reduction under the average banking and trading (ABT) provisions." Specifically, what begins on July 1, 2000? Is this date correct?

Answer: The NPRM proposed to require refiners who wish to generate credits during 2000-2003 to submit a sulfur baseline application to EPA by July 1, 2000. However, the date for submission of a sulfur baseline application for early credit generation was changed in the final rule to September 30 of the year in which the refiner plans to begin generating credits. *See* § 80.290(a). Beginning in 2000, refiners who wish to generate early credits are also required retain records of the sulfur content of each batch produced by the refinery for any year in which the refinery generates credits. In addition, refiners who are not already registered under the RFG/CG program must register with EPA by September 30 of the year prior to the first year of credit generation, or by May 10, 2000, for credits generated in 2000.

12. **Question:** In a scenario where two refineries are owned by the same parent company, is there any situation in which one refinery (GPA refinery) could not use allotments and/or credits that were generated by the other refinery (non-GPA refinery)?

Answer: Credits generated by the non-GPA refinery (or any other refinery) may be used by the GPA refinery for demonstrating compliance with the refinery's GPA gasoline standard, if used in accordance with the provisions for credit use in § 80.315. Although allotments may not be used to achieve compliance with the refinery or importer annual average standards at § 80.195 (except in 2005), allotments may be used to demonstrate compliance with the GPA gasoline standards. *See* § 80.216(d). Therefore, allotments generated by the non-GPA refinery may also be used by the GPA refinery for demonstrating compliance with the refinery's GPA standard, if used in accordance with the provisions for allotment use in § 80.275(c). However, in the scenario described above, allotments would only be generated if the company is subject to the corporate pool average standards under § 80.216(f) (i.e., less than 50 percent of the company's gasoline production is GPA gasoline.)

13. **Question:** It is our understanding that blender terminals are not able to establish a baseline or generate early credits under the sulfur regulations. Is this correct? If not, how would a sulfur baseline be determined for that party? For example, if a downstream terminal is

registered as a refiner and produces gasoline by blending a naturally produced material such as natural gasoline or condensate with other gasoline blending components, how would that facility be treated under the sulfur regulations?

Answer: Under the sulfur regulations, any person who produces gasoline by blending blendstocks is a refiner subject to all of the standards and requirements of the sulfur rule. *See* §§ 80.2(h) and (i). However, the sulfur regulations specify that early credit generation is limited to refiners who produce gasoline from crude oil. *See* § 80.285(a). As a result, a refiner who only produces gasoline by blending blendstocks, such as blending natural gasoline or condensate with other blending components, would not be able to generate early credits, and therefore, would not need to establish a sulfur baseline. However, a blender refiner may participate in the credit program in 2004 and thereafter based on reductions from the 30 ppm sulfur standard. *See* § 80.285(b). A blender refiner may generate early credits at any of its refineries that produce gasoline from crude oil.

14. **Question:** During the period of early credit generation (2000-2003), would a foreign refiner be able to earn credits for gasoline components exported to the U.S. for blending into finished gasoline?

Answer: Under the regulations, early credits are generated based on finished gasoline produced during the averaging period. *See* § 80.305. As a result, a refiner would not be able to generate early credits based on gasoline components. As discussed in Question 13 above, the blender refiner who blends the components into finished gasoline also would not be able to generate early credits, since the regulations only allow refiners who produce gasoline from crude oil to generate early credits.

15. **Question:** Can allotments be generated by blender refiners who combine blendstocks with finished gasoline downstream from the refinery?

Answer: EPA intended for generation of early allotments, like early ABT credits, to be limited to refiners who produce gasoline from crude oil. We intend to revise the regulations in accordance with this approach in a future rulemaking. Like ABT credits, blender refiners may generate allotments in 2004 and 2005.

16. **Question:** Section 80.315 states that the credit transferor must apply any credits necessary to meet the transferor's applicable average standard before transferring credits to any other refiner or importer, and that no credits may be transferred that would result in the transferor having a negative balance. It is not clear why a refiner can carry over a negative balance under § 80.205(e) because he blended high sulfur gasoline, but not because the refiner sold credits.

Answer: Section 80.205(e) is included in the regulations to provide additional flexibility in the early years of the sulfur program for those refiners who have difficulty meeting the sulfur standard due to circumstances such as an unexpected shutdown or an inability to obtain sufficient

credits. Under this provision, such refiners are not required to purchase credits before utilizing the deficit carry-over provisions. However, EPA believes that a refiner who has generated or otherwise obtained credits should use those credits to achieve compliance in the event of a deficit rather than transferring the credits and carrying the deficit over to the next averaging period. As a result, the regulations provide that a refiner may not transfer credits if doing so would create a deficit for that refiner for that averaging period.

17. **Question:** There is significant difference between "refiner" and "refinery". Portions of the regulations use "refiner" where "refinery" is the appropriate term. While it may be clear from the context that "refinery" is meant, text should be changed to avoid any possible misunderstandings.

Answer: We agree with the comment and intend to make these clarifications in a future rulemaking. These clarifications would not affect the regulatory requirements in the current final rule.

SAMPLING AND TESTING

1. **Question:** Can a refiner or importer use gasoline sulfur test methods other than ASTM D 2622-98, especially for sulfur levels of 10 ppm and less?

Answer: The rule designates ASTM D 2622 as the benchmark test method by which compliance will be determined, and that is the test that the Agency typically will use in establishing compliance. However, the rule does permit alternative test methods to be used for affirmative defense purposes, but only if the alternative test method has been appropriately correlated to the regulatory method, and the alternative test protocols have been followed. See § 80.330(c). EPA hopes to publish a proposal for a performance based measurements systems rule (PBMS), which would ultimately codify standardized procedures by which a party may qualify alternative test methods.

2. **Question:** If a refiner produces a gasoline batch less than 10 ppm sulfur by ASTM D-2622, how can an average be obtained with this test method without losing the lower sulfur level batch in the average? For example:

Batch 1 100,000 BBLs at 32 ppm S.

Batch 2 20,000 BBLs at 1 ppm S.

Average using 1ppm actual S would be 29.33 ppm

Average using 10 ppm S D-2622 (lower detectable level) would be 30.83 ppm

Can EPA specify a method that actually measures less than 10 ppm to determine measurements below 10 ppm sulfur? Industry needs some additional clarification on use of method D- 2622 for determining values less than 10-20 ppm.

Answer: The test method D-2622 was originally selected because the technique of Wavelength Dispersive X-ray Fluorescence has been widely demonstrated to exhibit excellent linearity with little or no bias across the range of sulfur concentrations present in commercial motor fuel mixtures. This absence of bias is central to the concerns regarding variability at very low levels of sulfur in motor fuels.

In general, EPA believes that the method selected, D-2622, has demonstrated sufficient linearity that results may be entered for their actual reading, not truncated to the limit of quantification (LOQ) when the actual reading is lower. For example, if the laboratory in question believes that their LOQ is 10 ppm, and a particular sample actually reads as containing 5 ppm, the answer does not have to be changed to 10 ppm for reporting.

In the example presented in the question, the result for the 1 ppm sample is either truncated to the method's LOQ, or assumed to be read at the upper limit of its statistical boundary (in other words, the reading was as bad as it could acceptably be). While this may yield a non-complying average in this case, in fact the case is not representative of what is realistically expected in commerce. According to the regulation, the reporting period for the averaging of sulfur results is one year. EPA is not aware of refineries that can afford to produce only two batches in a year.

Because the selected method is assumed to be linear and without bias, it is reasonable to assume that over the one year reporting period, the randomness that occurs in sulfur measurement will average to zero. That is, high results will have offsetting low results. This is the definition of zero bias.

In fact, EPA believes that this sample problem can be contrived for any commonly available test method, as all test methods demonstrate some degree of randomness in their use. In addition, this randomness is not confined to the lower end of the concentration scale. Typically, ASTM variability rates are expressed as a function of concentration. This means that in most cases, the variability in results from samples containing higher concentrations are greater in absolute terms than the variability of samples of lower concentrations. For example, if a method has a variability rate that is expressed as variability = conc. * 10 percent, a sample containing 500 ppm could be read as off by as much as 50 ppm, while a sample containing 20 ppm could be read as off by only up to 2 ppm. Since the actual averaging scheme is a linear one, the 50 ppm error will clearly dominate.

As in the example in the question, this is a contrived situation, unlikely to be seen in commerce. In fact, most ASTM test methods have variability that is expressed as a combination of a proportional part and a linear part. This example does serve to demonstrate that within the averaging scheme in the regulation, smaller individual results have much less impact on the overall averaged result than larger ones.

EPA believes that if test method D-2622 is calibrated carefully, with particular attention paid to the origin by the inclusion of blanks in the calibration standard set, the variability that

results from samples of lower concentration will be averaged out over the reporting period. The outcome of this will be that inappropriately noncompliant averages will not be observed.

3. **Question:** What test requirements exist for determination of the sulfur content of denatured ethanol? What test method must be used to determine the sulfur content of ethanol? In the absence of an approved test method, what guidance can the Agency provide fuel ethanol producers to avoid a violation? Will the Agency consider postponing enforcement of the ethanol sulfur specification until an ASTM test method for sulfur in ethanol is established?

Answer: The regulations do not require an ethanol blender, producer or supplier to test ethanol for sulfur content. The regulations do prohibit blending denatured ethanol into gasoline if the sulfur content of the denatured ethanol exceeds 30 ppm. *See* § 80.385(e). We expect the sulfur content of denatured ethanol would seldom approach 30 ppm under current ethanol production industry practices. To address ethanol blender concerns about the possible receipt of high sulfur ethanol, however, these blenders might choose to establish commercial (*e.g.*, contractual) arrangements with their suppliers to only supply ethanol whose sulfur content does not exceed 30 ppm. Further, the ethanol blenders could create quality assurance programs which periodically test received ethanol for compliance of sulfur content.

We believe that ASTM D 2622-98, the designated method for testing for sulfur content of gasoline, will be useable for this testing purpose, as long as the calibration of the instrument is performed with an ethanol blend that is representative of the samples that are expected to be tested. Since we believe this ASTM method is sufficiently precise to determine if the sulfur content of the denatured ethanol exceeds 30 ppm, we do not believe there is a need to postpone enforcement.

4. **Question:** Section 80.46(a) was amended by the rule to require the use of ASTM D-3246 to determine the sulfur content of butane. Many refiners and butane suppliers do not currently use that method. Requiring a new method prior to the 2004 effective date of the gasoline sulfur standards would be costly for these companies. What is the effective date for the use of ASTM D 3246-96 for testing butane for sulfur content?

Answer: The final gasoline sulfur rulemaking amended 40 CFR § 80.46(a) to require the use of ASTM D 3246-96 to determine the sulfur content of butane. We did not intend to require the use of this new test method to be effective immediately. We intended that it should take effect January 1, 2004, when a butane sulfur content standard becomes effective for refiners who produce gasoline by blending butane to previously certified gasoline. Until January 1, 2004, any appropriate ASTM method may be used for testing the sulfur content of butane. We intend to take regulatory action to clarify the effective date of the regulatory butane test method.

5. **Question:** Under § 80.330(a), a refiner or importer must sample and test each batch of gasoline for sulfur content prior to shipping the gasoline from the refinery or import facility, effective January 1, 2004, or January 1 of the first year of credit generation, whichever comes

first. Paragraph (a)(3) provides an exception to the requirement to test before the gasoline leaves the facility for parties who test composited samples. Is a refinery that tests every batch of conventional gasoline produced (*i.e.*, does not test composite samples) exempt from the requirement to test prior to the gasoline leaving the refinery, prior to 2004?

Answer: Under the provisions of § 80.330(a), all refiners and importers who participate in early credits or allotments generation would be required to test each batch of gasoline they produce or import for sulfur content prior to the gasoline leaving the facility, except that: (1) parties who collect and test composited samples of conventional gasoline would be allowed to continue that practice until January 1, 2004; and (2) parties who have approved in-line blending waivers are exempt from the requirement to test before the gasoline leaves the refinery even after standards go into effect starting January 1, 2004. The rule did not address whether parties who currently test each batch of gasoline by testing a representative sample taken from the certification tank (*i.e.*, who do not test composite samples) would be exempt from testing each batch prior to the gasoline leaving the facility prior to January 1, 2004. We did not intend to make refiners who test every batch of CG to have more severe requirements than refiners who test composite samples. Until January 1, 2004, refiners who test each batch of gasoline may release the gasoline prior to obtaining a test result. We intend to clarify this in a technical amendment to the regulation.

6. **Question:** Is a conventional gasoline refinery, participating in early credits generation, and using in-line blending, required to have an in-line blending waiver in order to participate in the early credit generation program (*i.e.*, prior to 2004)?

Answer: Section 80.330 requires that a refinery must determine the sulfur content each batch of conventional gasoline or RFG produced prior to the gasoline leaving the refinery unless the refinery has an approved in-line blending waiver under § 80.65(f)(4). A refinery that currently produces conventional gasoline by in-line blending but has no in-line blending waiver cannot participate in the early credits program unless it obtains an in-line blending waiver. However, the in-line blending waiver for conventional gasoline is only required to address sulfur sampling and analysis. We will make every effort to review in-line blending waivers promptly. Where appropriate, EPA may determine that the in-line blending waiver may apply retroactively to the date that the refinery first met all requirements for an in-line blending waiver.

7. **Question:** If a refinery that is participating in the early credits program is testing composite samples of conventional gasoline prior to 2004, must it nevertheless retain samples from each batch of gasoline produced?

Answer: Section 80.335(a) provides that beginning January 1, 2004, or January 1 of the first year allotments or credits are generated under §§ 80.275 and 80.305, whichever is earlier, a refiner must retain representative samples of the gasoline batch samples analyzed under the requirements of this subpart. Composited samples are treated as representative of a single batch of gasoline. *See* § 80.330(a)(3). Compositing of samples for sulfur testing purposes is allowed

until January 1, 2004. Hence, prior to January 1, 2004, those refiners who analyze composited samples of conventional gasoline are required only to retain portions of the composited samples pursuant to §§ 80.330(a)(3) and 80.335(a)(1).

8. **Question:** Section 80.335(a)(2) requires refiners to retain sample portions for the most recent 20 samples collected, or for each sample collected during the most recent 21 day period, whichever is greater. Is a refinery that produces only one or two batches of gasoline per year required to retain samples for up to 10 or 20 years?

Answer: The cited section of the regulation specifies the minimum number of batch samples from a refinery, which once created, must be maintained (twenty). The regulation does not specifically address the maximum amount of time that any particular sample must be maintained. This was not considered to be an issue since the Agency assumed that refineries and importers produce or import a substantial amount of batches each year. Such parties would accrue the twenty batch minimum in relatively short order, so that they would effectively be able to dispose of any additional, older samples quickly. This question indicates, however, that at least one refiner or importer handles less than a handful of batches each year, so that its batch samples might have to be retained for an extensive amount of time, such as between ten and twenty years. The Agency did not intend for refiners to be required to maintain sulfur samples for an excessive amount of time. We will address this issue through a future rulemaking.

9. **Question:** Several denaturants are used for fuel ethanol, including conventional gasoline, raffinate, LSR gasoline and natural gasoline. The predominant denaturant used is natural gasoline, which could be described as a “gasoline blendstock.” Does EPA intend to treat an oxygenate blender using ethanol denatured with denaturants other than unleaded gasoline as a “refiner” for the purposes Tier 2 compliance?

Answer: The gasoline sulfur rule states that oxygenate blenders who blend oxygenate into gasoline downstream of the refinery are not subject to the rule’s refiner requirements, but are, instead, subject to downstream standards and prohibitions. *See* § 80.212. The Agency interprets the term oxygenate blenders under the gasoline sulfur rule to include those ethanol blenders who blend ethanol into gasoline, even though the ethanol may contain gasoline denaturants, in a manner consistent with ASTM specifications, which are not unleaded gasoline. This inclusive interpretation makes the gasoline sulfur rule’s treatment of ethanol blenders consistent with that found under the RFG/CG and oxygenate blender programs. Under these programs, ethanol blenders, regardless of the denaturant involved, are exempted from those provisions of the programs under 40 CFR Part 80 which are applicable only to refiners and importers of gasoline. The rationale for this inclusion under these programs is that the blending of only denatured ethanol (up to 10 percent by volume) should not cause the gasoline to violate the RFG/CG volatility standards, where the ethanol is added in compliance with regulatory requirements and where the blended oxygenate does not otherwise affect the quantity or quality of gasoline.

The Agency believes that the same rationale applies under the sulfur program, provided

that the ethanol blender does not blend into the gasoline ethanol containing more than 30 ppm sulfur. Compliance with this sulfur content prohibition should ensure compliance of the blended gasoline with the low sulfur requirements of the rule. Due to this prohibition, the Agency believes that market forces will ensure the use of low sulfur denaturants in ethanol to be sold to ethanol blenders.

10. **Question:** A refiner produces a batch of gasoline at its refinery. It collects a sample of the gasoline and conducts certification testing. The sulfur content test result is less than the 80 ppm refinery level standard. The gasoline is then moved to another tank within the refinery, where it is commingled with several other certified batches whose certification test results were also less than 80 ppm. The gasoline is sampled and tested subsequent to being moved. Does the 95 ppm downstream sulfur standard apply to this subsequent test result?

Answer: The downstream standard applies to samples of gasoline subsequent to movement of the gasoline from the tank in which certification sampling is conducted, even when these subsequent samples are collected within the refinery or import facility where the gasoline is produced or imported. Thus, a refiner or importer may conduct a quality assurance program of the gasoline located at the refinery or import facility that previously has been certified, and apply the downstream cap standard when evaluating the quality assurance samples.

11. **Question:** A refiner or importer produces or imports a batch of gasoline and collects a sample of that gasoline for certification testing. The refiner's or importer's certification test result for the gasoline is less than 80 ppm. EPA takes a sample of the same batch of gasoline from the certification tank. (Or a refiner or importer submits a retained sample of certified gasoline to EPA.) The EPA test result for the gasoline is greater than the 80 ppm refinery level standard. Would EPA consider the sample to be in violation of the refinery level cap standard? Under the same scenario, but where the EPA test result is also under 80 ppm, but is greater than the refiner's test result, would EPA consider the refiner's test result invalid for purposes of calculating the average annual sulfur level of the refiner's gasoline?

Answer: EPA would determine whether the batch is in violation of the cap standard based on whether it exceeds the 80 ppm refinery level standard. If the EPA test result is greater than 95 ppm, the batch would be in violation, since any test result over 95 ppm exceeds ASTM reproducibility for gasoline whose true sulfur value is less than 80 ppm. If the EPA test result is greater than 80 ppm but less than 95 ppm, EPA would reserve the right to determine whether the true sulfur value of the sample is greater than the 80 ppm refinery level cap. EPA could make this determination by conducting multiple analyses on the sample, by submitting the sample to other laboratories for testing, by testing other samples collected from the same batch of gasoline, or by any other means that would give EPA sufficient confidence that the sulfur level of the sample exceeds 80 ppm.

In the second scenario, EPA would consider the refiner's annual average calculations to be incorrect if we determine that the refiner's test results demonstrate a bias in favor of batch certification testing for sulfur content that is less than the true value. EPA might determine such

a bias, for example, based on testing a series of retains or other samples, and comparing EPA's sulfur results with those of the refiner. It is possible for such a bias to exist even though all samples tested are under the cap standard, and even if EPA test results do not necessarily differ from the refiner's by greater than ASTM reproducibility.

DOWNSTREAM TESTING FOR S-RGAS

1. **Question:** When we transfer gasoline from our terminals we generate two PTDs for each transfer: (1) a bill of lading (BOL) from the terminal for custody transfer, and (2) an invoice generated by the accounting staff for title transfer. These two PTDs are generated not only at different locations, but also by different programs. We cannot realistically guarantee that the accounting department's invoice PTD will have the same information on it as to S-RGAS status as will the terminal's BOL. This is because the S-RGAS status information must be generated based on testing which will only be performed at the terminal. We do not have an automated process to transfer this changing status information from the terminal to the accounting department. Therefore, to ensure consistency between the two PTDs, we will have to rely on the prompt, accurate transmittal of this information 100 percent of the time. Such foolproof, 100 percent successful, manual transmittal of varying S-RGAS status information cannot be assumed. How can we prevent PTD violations from occurring due to the varying manner in which we create our two PTDs?

Answer: The regulation requires that on each occasion when downstream parties transfer title or custody to S-RGAS or mixtures of this gas, the transferor must provide the transferee product transfer documentation identifying the S-RGAS status and standard applicable to such gasoline. *See* § 80.210(e)(2). Whether the gasoline is classified as S-RGAS on the PTD depends upon the gasoline being comprised in whole or in part of S-RGAS, the receipt of a PTD stating that the product is S-RGAS, and a test result confirming that the sulfur content exceeds the regulatory threshold under § 80.210(d)(3). The intent of these PTD identification requirements is to provide the transferee with accurate S-RGAS information about the gasoline being received. If a downstream party transferring custody of gasoline provides accurate information as to S-RGAS status and sulfur standard, as applicable, on its BOL to its transferee, the Agency believes that this goal of accurate S-RGAS information transmission is effectively satisfied. Therefore, in situations in which both a custody PTD and a separate title PTD are generated by a downstream party for the same gasoline, the Agency will consider the requirement of S-RGAS status and standard transmission satisfied if the custody transfer PTD accurately provides the required information, and the title transfer PTD also provides that same information, or it indicates that the S-RGAS information is contained on the custody PTD.

2. **Question:** Truckers may obtain both premium gasoline and regular gasoline from a terminal in order to supply a retail outlet with midgrade gasoline. In such cases, if a truck obtains a load of gasoline from a terminal that consists of a mixture of gasoline from a terminal tank that is properly designated as S-RGAS, and gasoline from another tank that is not S-RGAS, how must the terminal and trucker classify the gasoline, and must an additional sample be obtained

and tested of the combined product from the 2 storage tanks?

Answer: The regulation specifically exempts gasoline in trucks from the testing requirement for S-RGAS, and instead allows truckers to rely on the test result of the terminal supplying the truck carrier. *See* § 80.210(d)(4). Where a tanker truck receives a load of midgrade gasoline that is comprised of S-RGAS and non-S-RGAS dispensed into the same compartment for the purpose of making midgrade gasoline, whether through in-line blending or otherwise, the transferred gasoline could properly be classified on the PTD as S-RGAS, provided that the intent was to create mid-grade gasoline. However, If a relatively small volume of S-RGAS were to be blended with non-S-RGAS, the gasoline in the tanker truck could not be classified as S-RGAS, since such blending is not consistent with the need to make midgrade gasoline from premium and regular gasoline.

3. **Question:** A terminal provides gasoline to a truck at the terminal's truck rack at the same time the terminal is receiving gasoline into the same storage tank that is supplying the truck. The gasoline already in the terminal's storage tank is properly classified as containing S-RGAS before the new delivery of gasoline into the tank. The new delivery of gasoline into the terminal's tank is not classified by the pipeline as S-RGAS. How should the gasoline being supplied to the truck be classified on the terminal's PTDs, and at what point does the classification change?

Answer: Under the regulation, the terminal must obtain a representative sample of gasoline from the storage tank and test it for sulfur content after receipt of the new load of gasoline into the terminal tank in order to continue to qualify the gasoline in the tank as S-RGAS (§ 80.210(d)(3)). Assuming the new receipt of gasoline is loaded into the terminal storage tank as per normal practices, the terminal would not be required to retest the tank to determine if it still qualifies as S-RGAS until the new load is fully received into the storage tank. Until that time, in the above scenario, the truck carrier could be given a PTD designating the gasoline as S-RGAS. Subsequent to the full receipt of the gasoline into the storage tank, however, a new sample must be obtained from the tank and be tested to determine if continuing to classify gasoline in the tank as S-RGAS (on PTDs), is still appropriate.

4. **Question:** Assume that the gasoline contained in the storage tank is not classified as S-RGAS when the truck begins to receive product, but gasoline classified by the pipeline as S-RGAS is being loaded into the terminal storage tank from a pipeline as the truck is being loaded. The gasoline going into the terminal storage tank is being bottom-loaded, and the gasoline going to the truck rack is also drawn from near the bottom of the terminal storage tank. May the terminal classify the gasoline being loaded to the truck as S-RGAS even though the gasoline in the terminal storage tank is currently classified as non-S-RGAS and may ultimately be classified as non-S-RGAS after sampling and testing subsequent to full receipt of the new load of gasoline from the pipeline?

Answer: Under the regulation the terminal must sample and test its gasoline subsequent to the receipt of the transferred gasoline into the terminal storage tank in order to qualify the

gasoline in the tank as S-RGAS. However, it is a common industry practice for terminals to supply gasoline from a storage tank at the same time the tank is also receiving product from a pipeline. Where a load of gasoline that is classified by the pipeline as S-RGAS is being received into the terminal storage tank, until full receipt of the load, a sample that meets the requirements of the regulation cannot be obtained from the tank. Even when a sample is ultimately taken and tested subsequent to full receipt of the load from the pipeline, the sample may not actually be representative of the gasoline that had previously been loaded into the truck, because in many situations the gasoline is being bottom-loaded into the terminal storage tank and is also being supplied to the truck rack from the bottom. Therefore, the truck may have received gasoline that would not have the same sulfur test result as would a sample that was obtained from the completed mixture. Since parties will not encounter this issue until January, 2004, we are studying the situation, and will address it through appropriate later guidance, either through a Q&A response or through regulatory action prior to that time.

CALIFORNIA GASOLINE EXEMPTION

1. **Question:** Certain metropolitan areas in the western U.S. (but outside of California) may obtain fuel program waivers and adopt programs that require the use of gasoline meeting California requirements on at least a seasonal basis. Section 80.375(c) specifies that designated California gasoline must ultimately be used in the state of California and not elsewhere, and that designated California gasoline must be kept segregated from gasoline that is not California gasoline at all points in the distribution system. The segregation requirement could impose a burden on supplying California gasoline to a non-California area subject to a state program requiring California gasoline. Do federal rules preempt these states from making a requirement for California gasoline use? If not, would EPA consider removal of the segregation requirement?

Answer: EPA's adoption of gasoline sulfur standards preempts state actions to prescribe or enforce fuel sulfur controls. States desiring to have gasoline sulfur control programs approved in their SIPs need to obtain a waiver of EPA's preemption under § 211(c)(4)(C) of the Clean Air Act. *See* 65 FR at 6765. It is possible that a *state fuel* program would require the sale of gasoline meeting CARB standards within the state's jurisdiction as a means of compliance with the state program. The current regulations require California gasoline to ultimately be used in California to be exempt from the sulfur standards. We are reviewing issues related to the application of this limitation in the situation where gasoline meeting CARB standards may be required under a state program that has received a § 211(c)(4)(C) waiver from EPA. We will address these issues in a future guidance or rulemaking.

2. **Question:** Must a refinery that produces both California gasoline and federal RFG designate each batch produced as either federal RFG or California gasoline, and maintain segregation of both products, even though the gasoline meets the requirements of both programs?

Answer: Section 80.375(c) requires that each batch of California gasoline be designated as such by the refiner or importer, and that California gasoline be segregated from gasoline that is not California gasoline at all points in the distribution system. The designation and segregation

requirements for California gasoline are necessary to assure the enforceability of the federal gasoline sulfur rule and RFG rule. Because the federal sulfur rule refinery standard is an annual average standard, there would be no way to ensure that a refinery producing both California gasoline and federal gasoline is in compliance with the average standard unless gasoline designated for California use is actually used in California and gasoline designated for 49 state use is actually used in the 49 states.