Reconsideration of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review

AGENCY: Environmental Protection Agency (EPA)

ACTION: Reconsideration of the final rule.

SUMMARY:

DATES:

ADDRESSES:

FOR FURTHER INFORMATION CONTACT:

SUPPLEMENTARY INFORMATION:

Organization of this document. The information in this preamble is organized as follows:

F. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
G. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
H. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51
I. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

I. Executive Summary

[Placeholder]

II. General Information

A. What is the source of authority for this reconsideration action?

The statutory authority for this action is provided by sections 111(b) and (d) of the Clean Air Act (CAA) (42 U.S.C. 7411(b) and (d)).

B. Does this action apply to me?

Regulated entities. Categories and entities potentially regulated by this action are shown in Table 1 of this preamble.

TABLE 1—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY NSPS ACTIONS

Category	NAICS Code[1]	Examples of regulated entities
Industry	211120	Crude Petroleum Extraction.
	211130	Natural Gas Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal Government	. . . .	Not affected.
State and Local Government	. . . .	Not affected.
Tribal Government	921150	American Indian and Alaska Native Tribal Governments.

[1] North American Industry Classification System (NAICS).

This table is not intended to be exhaustive but rather provides a guide for readers regarding entities likely to be affected by the NSPS actions. Other types of entities not listed in the table could also be affected by these NSPS actions. To determine whether your entity is affected by any of the NSPS actions, you should carefully examine the applicability criteria found in the final NSPS rules. If you have questions regarding the applicability of the NSPS rules to a particular entity, please contact the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section of this preamble.

C. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this action is available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this proposed action at [*web address*]. Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the proposal at this same website.

D. Judicial Review and Administrative Review

[Placeholder]

III. Reconsideration Issues

On March 8, 2024, after soliciting and considering public comments, the EPA took final action on the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (89 FR 16820). Following promulgation of the final rule, the EPA received a joint petition for reconsideration from the American Petroleum Institute (API) and the American Exploration and Production Council (AXPC). A copy of the petition is available in the docket for this rulemaking. The API-AXPC petition requested that EPA reconsider the final rule to reassess the standards and compliance assurance requirements for flares and enclosed combustion devices, as well as several other issues that are not addressed herein.[1] The petitioners stated that the EPA's standards and compliance assurance requirements for flares and enclosed combustion devices are technically infeasible, logistically impossible to meet for a vast number of immediately affected facilities, and unnecessary in the majority of oil and natural gas operations. The petitioners also stated that the final rule's allowance of temporary flaring for unique situations should be extended from twenty-four hours to seventy-two hours to account for logistical issues stemming from repair and maintenance of geographically isolated facilities. [Description of other issues to be included.]

On May 6, 2024, the EPA sent a letter to the petitioners informing them that: (1) the EPA was granting reconsideration requests on two specific issues (described in the next paragraph), (2) the EPA intended to issue a Federal Register notice on the issues for which the Agency granted reconsideration, and (3) the EPA was continuing to review the other issues in the petition for reconsideration and may choose to initiate reconsideration of additional issues in the future. Copies of the letters to petitioners are available in the docket for this rulemaking (*See* Docket ID Nos. [*insert docket ID #*]).

On May 6, 2024, API and AXPC submitted a second joint petition for reconsideration, which EPA is in process of evaluating.

The EPA proposes to review the selected issues for which reconsideration was granted in EPA's May 6, 2024 letter [, as well as other issues]; specifically, the following aspects of the final rule: (a) standards and compliance assurance requirements for flares and enclosed combustion devices pertaining to vent gas net heating value (NHV), as promulgated in the final rule and codified at 40 CFR part 60, subparts OOOOb and OOOOc; (b) the extension of temporary flaring provisions

[1] In addition to the aforementioned standards and compliance assurance requirements for flares and enclosed combustion devices, API-AXPC believes that it would be expedient for EPA to address the following matters in this rulemaking, as these are also control device-related issues that stem from the final rule with impending compliance deadlines: Clarification of enclosed combustion device performance testing procedures, allowance for alternative test methods for control devices, such as Other Test Method 52 (OTM-52) and Method 22, as well as use of alternative technology, such as self-contained process controllers, low-pressure control device flow monitoring requirements, and allowances for limited vapor recovery unit (VRU) downtime.

promulgated in the final rule and codified as 40 CFR 60.5377b(d) and 60.5391c(c); and (c) [other issue(s)].

A. Vent Gas Continuous NHV Monitoring and NHV Demonstration Requirements for Flares and Enclosed Combustion Devices

NSPS OOOOb and EG OOOOc contain various compliance requirements to ensure that combustion control devices that are being used to meet a 95.0 percent emission reduction standard can continuously demonstrate this level of control of emissions from affected and designated facilities. Owners and operators of enclosed combustion devices and flares must demonstrate compliance with this control efficiency, in part, by maintaining the NHV of the gas sent to the device above a minimum limit set in NSPS OOOOb and EG OOOOc. This ensures that the gas vented to these control devices is sufficiently combustible to achieve at least 95.0 percent reduction of VOC and methane.

The final rule promulgated continuous monitoring provisions requiring that the vent gas NHV remain above the required minimum value and requiring owners and operators to demonstrate compliance with this requirement through continuous monitoring of the NHV of the inlet gas to an enclosed combustion device or flare at standard conditions, or for certain control devices, to alternatively demonstrate the vent gas NHV consistently exceeds the applicable minimum NHV limit. The EPA finalized these requirements at §§60.5417b(d)(8)(ii) and (iii) and 60.5417c(d)(8)(ii) and (iii). Where owners and operators are required to continuously monitor NHV of the control device's inlet gas stream, the final rule allows the use a calorimeter, chromatograph, mass spectrometer, or a grab sampling system. Where operators alternatively demonstrate the NHV consistently exceeds the minimum limit, the final rule allows them to do so through continuous monitoring using the same methods in the previous sentence or by collecting samples twice daily, in either case for 14 consecutive operating days. The final rule did not require continuous NHV monitoring for enclosed combustion devices or flares whose only inlet stream is associated gas from a well affected or designated facility, as discussed in section III.A.1. of this preamble.

1. Vent Gas Continuous NHV Monitoring Requirements

Vent gas streams at crude oil and natural gas facilities have limited compositional variability, and the composition of each stream is relatively consistent over time. The vent gas streams at crude oil and natural gas facilities are primarily comprised of methane and VOCs with relatively high NHV. The EPA proposes revising §§60.5417b(d) and 60.5417c(d) to recognize that there is no need for owners or operators at crude oil and natural gas facilities to continuously monitoring vent gas NHV, because in all but a few circumstances where operators introduce inert gases into facility processes, the expected NHV of associated gas and all other vent gas sources far exceed the minimum NHV requirements in NSPS OOOOb and EG OOOOc.

As explained in the preamble to the final rule, where associated gas from a well affected facility is the only inlet stream to the enclosed combustion device or flare, owners and operators are not required to conduct continuous monitoring of the NHV or the alternative NHV sampling

demonstration. Associated gas is the natural gas released in the initial stage of separation.[2] It has the lowest NHV and highest vapor pressure of any natural gas at a well production facility because associated gas is primarily methane, which has an associated NHV of 909.4 Btu/scf (source: GPA 2145), and other lighter-end hydrocarbons with even higher associated NHV than methane. Continuous monitoring is not needed to confirm the NHV of associated gas is above minimum requirements, because associated gas is high in methane content and similar in quality to sales grade gas. Due to the high methane content and quality of the associated gas, the NHV of the inlet stream to the enclosed combustion device or flare is considered to be sufficiently above the minimum required NHV for the inlet gas.[3]

Additionally, the EPA considered a letter submitted by SPL Labs, which states that, based on their extensive experience analyzing thousands of vent gas samples, it would be exceptionally uncommon for the NHV of vent gas from oil and natural gas operations to fall below the threshold the EPA has set.[4] As SPL notes, when compared to sales quality natural gas (or the similar associated gas), which is methane enriched, vent gases from oil and natural gas operations downstream of the first stage of separation are comprised of exceptionally heavy gases (relative to air) that are typically depleted with respect to lighter hydrocarbon molecules such as methane and ethane, and enriched in molecules like propane, butane and pentane. As a result, these heavy gases have a lower vapor pressure (relative to a methane-enriched sales gas) and therefore do not "flash" from the liquid hydrocarbon stream until the final stage of separation. Whereas the NHV of methane is 909.4 Btu/scf, the NHV of propane, n-butane and n- pentane is 2,315 Btu/scf, 3,000 Btu/scf, and 3,707 Btu/scf, respectively. Therefore, unless there is a source of inert gas diluting the vent gas stream, such as sources of inert gas added by design, there should be no compositional reason the NHV of that gas would be under the applicable NHV limits set in the final rule. In SPL's experience, any vent gas sample falling below the applicable NHV limits would have been significantly diluted by an inert gas.

Petitioners provided data from a recent operator survey of NHV data conducted by API and AXPC through a third-party consultant. The data set included over 22,000 data points, 18 operators, and approximately 4,200 sites. The results showed more than 99.5% of the NHV data was at least 800 Btu/scf and more than 99.9% was at least 300 Btu/scf. These results appeared consistent across 12 basins, with the Permian, Anadarko, Gulf Coast (Eagle Ford), Williston (Bakken), and Powder River Basins collectively representing 99% of the data. The survey sampled 4,299 sources of low-pressure oil and natural gas operations gas streams that sampled various types of vapor streams. While some sources with multiple data points showed variability, the NHV was still well above 800 Btu/scf for those sources. Accordingly, and except as discussed below, the expected NHV of associated gas and all other natural gas at crude oil and natural gas facilities will far exceed minimum

[2] 40 CFR 60.5430b (defining "associated gas" in relevant part as "the natural gas from wells operated primarily for oil production that is released from the liquid hydrocarbon during the initial stage of separation after the wellhead").
[3] 89 Fed. Reg. 16966.
[4] SPL is the largest laboratory in the United States specializing in the analysis of hydrocarbon products, processing more than 225,000 natural gas samples each year.

NHV limits, and NHV monitoring is unnecessary to demonstrate the vent gas is sufficiently combustible.

The exception to the above is where the operator introduces inert gas upstream of the control device, either directly into a process or, for well sites and centralized production facilities, into the producing formation (*e.g.*, injecting carbon dioxide gas for enhanced oil recovery). The NHV data less than 900 Btu/scf in the survey were from known scenarios where large amounts of inert gases are expected. Operators know which scenarios or sites have the potential for large concentration of inert gases. These known scenarios include sites in fields using water or carbon dioxide (CO_2) flood enhanced oil recovery (EOR).

After careful consideration of the materials provided in the API/AXPC petition for reconsideration and the letter submitted by SPL, the EPA has determined there is a scientifically supportable basis for the contention that vent gas NHV at crude oil and natural gas facilities will sufficiently exceed applicable NHV limits for flares and enclosed combustion control devices. Accordingly, EPA proposes to revise §§60.5417b(d)(8)(ii) and 60.5417c(d)(8)(ii) to no longer require continuous NHV monitoring for enclosed combustion devices or flares controlling vent gas streams from affected and designated facilities located at crude oil and natural gas facilities, except where inert gas is introduced upstream of the enclosed combustion device or flare.

2. Vent Gas NHV Demonstration Requirements as an Alternative to Continuous Monitoring

In addition, EPA proposes revisions to the initial NHV sampling demonstration requirements in §§60.5417b(d)(8)(iii) and 60.5417c(d)(8)(iii) to remove the unnecessary burdens these provisions imposed on owners and operators. After reviewing the API/AXPC petition for reconsideration, EPA is proposing revisions to the final rule to clarify that owners and operators may sample from a location in the facility process, either at the same facility (*i.e.*, facility-specific) or at a representative facility, that is representative of the gas that will vent to the control device.

For facility-specific representative sampling, if multiple vent gas streams can vent to a flare or enclosed combustion device, then the owner or operator may sample each vent gas stream or the control device inlet. EPA proposes this revision because EPA recognizes control devices are often used intermittently and operators may need to divert a stream from a process to the control device to collect a sample at the control device inlet. For example, where an owner or operator normally routes storage tank vapors to a pipeline, the operator flares those vapors in limited circumstances. It is not EPA's intent to require owners and operators to divert vent gas to a control device for the purpose of capturing a sample for the NHV demonstration.

EPA believes that, as an alternative to collecting facility-specific representative samples, owners or operators of control devices located at well sites and centralized production facilities should also be able to utilize representative samples from nearby similarly situated well sites or centralized production facilities. We believe this is appropriate because requiring site-specific samples for every control device places an unnecessary burden on owners and operators where a sample from a nearby facility would be representative of the inlet gas to the control device. In

addition, increased demand for sampling analyses may exceed current laboratory capacity and make it infeasible to process all facility-specific samples by the applicable compliance deadline.

EPA reviewed state permitting programs that utilize a representative facility sampling approach and believes that under certain conditions a nearby well site or centralized production facility's production streams will accurately represent the gas that will vent to the control device at nearby facilities, so long as the following criteria are met:[5]

- The representative sample must originate from the same producing reservoir/formation as the process stream for which the representative sample will be used. This criterion is an appropriate limitation because it is likely that gas and liquids produced within the same geographical area in the same reservoir will have the same or very similar composition.
- The representative well site or centralized production facility must be located within 10 miles of the affected or designated facility for which the representative sample will be used.
- The petroleum liquids produced at the representative well site or centralized production facility and the well site or centralized production facility where the affected or designated facility is located must have an API gravity within three degrees. Similar API gravity is an indicator that the liquids are of similar composition. API gravity is used throughout the oil and gas industry to differentiate between heavy/light oil and condensate streams and can be easily obtained by the owner/operator. Three degrees takes into account the amount of error that might be present from a grab sample taken at the site that is not corrected for temperature and pressure.
- The process or vessel immediately before where the sample is collected must be within ±20 psi pressure and ±20 degrees Celsius temperature of the process or vessel stream that is being represented.
- It is recommended that the representative sample be as recent as possible, but no more than 3 years old, in order to provide the most current and accurate data.

To utilize a representative analysis from a nearby well site or centralized production facility, an owner or operator must maintain records demonstrating the above criteria were met.

We are also proposing revisions to the alternative NHV demonstration requirements in §§60.5417b(d)(8)(iii)(A)–(D) and 60.5417c(d)(8)(iii)(A)–(D) that will reduce burden while continuing to ensure vent gas streams meet minimum NHV requirements. The supporting letter from SPL has made the EPA aware that the amount of additional natural gas samples required in the final

[5] *See* Texas Commission on Environmental Quality, Representative Analysis Criteria (February 2012); *See also*, Colorado Air Pollution Control Division, PS Memo 20-04 (November 6, 2020); *See also*, Oklahoma Air Quality Division, Representative Sampling Guidance (September 15, 2020).

rule will result in sampling analysis demand that far exceeds current laboratory capacity across the country. To reduce the burden, we are proposing to allow the use of representative grab samples, rather than requiring the minimum time of collection for each sample be one hour, for the initial compliance demonstrations requirements. Section III.A.4. of this preamble discusses this proposal further. We believe these proposed revisions align with standard industry practice and requirements in other EPA rules and would continue to achieve the goal of demonstrating vent gas exceeds NHV limits.

To alleviate this burden, we propose to allow demonstration via 14 representative grab samples, which we believe provides a sufficient basis for exempting continuous NHV monitoring. There is precedent for this approach in refinery MACT, 40 CFR 63.670. Under 40 CFR 63.670, EPA allows NHV demonstration through grab sampling and does not require continuous NHV monitoring where the operator demonstrates—through 14 grab samples for frequently used flares, and only 7 for infrequently used flares—that flare vent gas stream has a consistent composition or a fixed minimum NHV. To reduce the burden on owners and operators, we propose as an alternative to collecting samples once a day for 14 days that operators could collect samples twice a day for 7 days, and we propose allowing breaks during the 7-day sampling period to account for weekends and holidays.

Where owners and operators complete the NHV demonstration through continuous monitoring, we propose to require use of 1-hour block averages to demonstrate the average NHV exceeds the applicable NHV limit. The block average approach is consistent with the continuous NHV monitoring requirements in the final rule at §§ 60.5417b(e)(5), (g)(1) and 60.5417c(e)(5), (g)(1). There, the final rule bases compliance on 3-hour block averages. We believe it makes sense to incorporate that concept in these revised rules as well.

In addition, because we expect the NHV at crude oil and natural gas facilities to be consistent over time, we propose that the NHV demonstration, grab sampling or continuous monitoring, should demonstrate that the average NHV exceeds the applicable minimum NHV limit without need of a buffer, and where the demonstrated NHV is at least double the applicable minimum NHV limit, no further demonstration is necessary.

Upon reviewing petitioner's comments, we propose to revise the requirements in §§60.5417b(d)(8)(iii)(F) and 60.5417c(d)(8)(ii)(F) for periodic grab samples that reveal that average NHV is lower than the applicable minimum NHV. This is how the final rule requires operators to demonstrate compliance with NHV limits if continuously monitoring NHV, and we believe it is appropriate that the demonstration in these provisions is based on average NHV.

We are also proposing to provide a period for commencing continuous NHV monitoring or re-completing the NHV demonstration if the periodic samples reveal the average NHV is lower than a minimum NHV limit. The final rule does not allow for a period to commence continuous monitoring or make an NHV demonstration, which means that a deviation may automatically occur through no fault of the operator. This was not our intent. Thus, we propose a 60-day period, which is necessary to acquire, install, and commission continuous monitoring equipment or to complete an NHV demonstration.

Lastly, we are proposing a clarifying revision to the demonstration re-evaluation requirements of §§60.5417b(d)(8)(iii) and 60.5417c(d)(8)(iii). As written, a revision in process operations that is expected to change the NHV of the gas sent to the enclosed combustion device or flare could trigger a requirement to re-evaluate vent gas NHV. This could be interpreted to include process operations revisions that increase the associated vent gas NHV. This was not the EPA's intent, and we propose a clarifying revision to reflect that only process operation revisions undertaken by the owner or operator that result in a reduction of the expected NHV of the gas will trigger a re-evaluation.

Similarly, we propose to revise §§60.5417b(d)(8)(iii)(E) and 60.5417c(d)(8)(iii)(E) to clarify that, to trigger the requirement to recomplete the NHV demonstration, an operator or owner must undertake an action to introduce additional inerts into the vent gas stream. An example of such an action is when an owner or operator commences an enhanced oil recovery operation that injects carbon dioxide into the producing formation. Taking such an action will require the operator to recomplete the NHV demonstration.

3. Vent Gas NHV Demonstration Analytical Methods for Compositional Analyses

We reviewed petitioners' comments regarding the required analytical method for analyzing the composition of vent gas to determine its NHV. We now understand that the analytical method in the final rule, ASTM D1945, is not widely available. Therefore, laboratories across the US will require additional time for method development of ASTM D1945 to have the capacity needed for operators to comply with the final rule. Based on comments received, we now understand the industry standard methods for determination of NHV are GPA 2261 (revised 2019) and GPA 2286 (revised 1995), and these methods are widely available. We believe either GPA 2261 or GPA 2286 are sufficient to analyze natural gas composition and determine NHV. Thus, we are proposing to allow use of GPA 2261 and 2286, in addition to ASTM D1945.

Lastly, where operators use a gas chromatograph to determine NHV, the final rule requires use of volume fraction. We propose to allow owners and operators to use weight fraction to determine the NHV of the vent gas, in addition to volume fraction. Weight fraction is commonly used to determine NHV and provides the same results as would using volume fraction.

4. Vent Gas NHV Demonstration Sampling Procedures

As noted in SPL's letter to the EPA, the description of the sample canister provided in the final rule suggests the EPA will require Summa canisters for vent gas collection. Summa canisters present logistical hurdles that make compliance with §§60.5417b(d) and 60.5417c(d) difficult because they are expensive, large, and were designed primarily for atmospheric gas sampling which are not appropriate for many of the affected and designated facilities under the final rule. To collect 1-hour samples by Summa cannister, restrictive flow metering devices will be required, and these devices primarily rely on a restrictive orifice to meter the gas into the Summa cannister.

Further, vent gas from affected and designated facilities under the final rule is potentially wet and includes contaminants. These characteristics will result in rapid fouling of Summa canisters

which will, in turn, cause errors in collection and potential contamination bias. In response to these comments, we are proposing to no longer require 1-hour sampling and to allow operators and laboratories to meet sample demand in a reasonable manner by collecting grab samples using single cavity stainless steel constant volume cylinders for sample collection so long as they are maintained according to the requirements set forth in 43 CFR 3175 (Onshore Oil and Gas Operations; Federal and Indian Oil and Gas Leases; Measurement of Gas).

B. Use of Refinery MACT Standards for Steam- and Air-Assisted Flare and Enclosed Combustion Device NHV Monitoring

In the final rule, EPA required that steam- and air-assisted flares and enclosed combustion control devices meet a minimum combustion zone NHV (NHV_{cz}) and, for devices that use perimeter assist air, a minimum NHV dilution parameter (NHV_{dil}).[6] The final rule also imposes associated continuous monitoring requirements to demonstrate that the control device meets the applicable NHV_{cz} and NHV_{dil}, as applicable.[7] These NHV_{cz} and NHV_{dil} requirements mirror those in 40 CFR Part 63, Subpart CC (Refinery MACT).

Petitioners comment that the NHV_{cz} and NHV_{dil} requirements from Refinery MACT are overly burdensome because crude oil and natural gas facilities are fundamentally different than petroleum refineries. We have reviewed the petitioners' comments, and after careful consideration, we have determined that petitioners have identified a basis for changing our approach to the continuous monitoring and demonstration requirements.

While the final rule includes provisions for alternate test methods and alternate NHV_{cz} and NHV_{dil} demonstrations in lieu of monitoring, alternative test methods have not been approved and alternative NHV_{cz} and NHV_{dil} demonstrations are not feasible for many control devices at crude oil and natural gas facilities. These alternate test methods are costly to implement and take time for EPA to approve, so they are not an option for immediate compliance. Moreover, the alternate NHV_{cz} and NHV_{dil} demonstrations are problematic given that many crude oil and natural gas facilities do not operate under steady state conditions. Thus, EPA has determined that the standards and monitoring requirements for steam- and air-assisted combustion control devices in the final rule must be revised to reflect the fundamental differences between refineries and the crude oil and natural gas facilities covered under the final rule.

Petitioners highlight the fact that refineries have potentially hundreds of unique process streams routed to a refinery flare header, the composition of refinery streams are highly variable, the crude oil feedstocks are processed through multiple units to derive multiple products and intermediates, and refineries routinely use inert gases in their processes (*e.g.*, clearing equipment for service, tank blanketing, *etc.*) which is reflected in the flare gas composition.

In contrast, crude oil and natural gas facilities have highly variable, intermittent flow rates, limited variability of gas compositions, and typically a small number of streams routed to a flare or

[6] 40 CFR §§ 60.5412b(a)(1)(iv)(C), (D) and 60.5412c(a)(1)(iv)(C), (D).
[7] *Id*. at §§ 60.5417b(d)(8)(vi) and 60.5417c(d)(8)(vi).

enclosed combustion device (often only one stream). This is particularly true for oil and natural gas production facilities where production is intermittent after the early stages of well production. For example, at these facilities, as production declines, management of liquids can mean that flow to the storage vessel can vary from essentially zero to high flow rates and quickly back to zero, which occurs often. This intermittent vent gas flow is characteristic across many oil and natural gas facility processes. These varying vapor flowrates make accurately monitoring NHV_{dil} and NHV_{cz} difficult or infeasible.

Lastly, we have reviewed petitioner's comments regarding cost feasibility, and the EPA is taking into account the fact that the costs for Refinery MACT controls and monitoring equipment at a refinery may be $1 million or more per control device, with major ongoing costs, and it is estimated that these costs will be much greater at crude oil and natural gas facilities covered by the final rule without the necessary utilities and instrumentation resources available for a large complex facility such as a refinery. EPA also understands that instrumentation is not widely available that would work reliably under the varying operating conditions at these facilities.

After consideration of petitioners' comments, we agree that applying refinery-oriented requirements to the crude oil and natural gas facilities covered by the final rule is not appropriate or cost effective, and we propose removal of §§ 60.5417b(d)(8)(vi) from the final rule.

We also note that we inadvertently included § 60.5417c(d)(8)(vi) in the final rule. As noted in EPA's comments in the final rule's preamble, EPA did not intend to include § 60.5417c(d)(8)(vi) in EG OOOOc.[8] For further discussion on the basis for not including these requirements for existing sources, please see the discussion in the preamble of the final rule. We propose to fix this inadvertent error and remove § 60.5417c(d)(8)(vi).

C. Extension of Temporary Flaring Provisions in Certain Situations

[Placeholder]

IV. Impacts of This Proposed Rule

A. What are the affected facilities?

B. What are the air quality impacts?

C. What are the cost impacts?

D. What are the economic impacts?

E. What are the benefits?

V. Statutory and Executive Order Reviews

[8] *See* 89 Fed. Reg. 16820, 16895/1, 16967/3.