ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 49

[EPA–R08–OAR–2015–0709; FRL–5872.1–01–R8]

RIN 2008–AA03

Federal Implementation Plan for Managing Emissions From Oil and Natural Gas Sources on Indian Country Lands Within the Uintah and Ouray Indian Reservation in Utah

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is promulgating a Federal Implementation Plan (FIP) under the Clean Air Act (CAA) and the EPA's implementing regulations that consists of emissions control requirements for existing, new, and modified oil and natural gas sources on Indian country lands within the Uintah and Ouray Indian Reservation (also referred to as the U&O Reservation) to address air quality in and around the Uinta Basin Ozone Nonattainment Area in northeast Utah. This U&O FIP establishes volatile organic compound (VOC) emissions control requirements for oil and natural gas production and processing on Indian country lands within the U&O Reservation. These requirements are consistent with those in place in areas within the Basin where the EPA has approved Utah to implement the CAA, and will help ensure that new development of oil and natural gas sources in the Basin will not interfere with attainment of the ozone National Ambient Air Quality Standard (NAAQS). VOC emissions control requirements for existing oil and natural gas sources have already been established in areas within the Basin where the EPA has approved Utah to implement the CAA, but did not exist for most sources on Indian country lands within the U&O Reservation. Additionally, this U&O FIP helps demonstrate that new development on Indian country lands within the U&O Reservation will not necessarily cause or contribute to an ozone NAAQS violation.

DATES: This final rule is effective on February 6, 2023.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–R08–OAR–2015–0709. All documents in the docket are listed on the *www.regulations.gov* website. In some instances, we reference documents from the dockets for other rulemakings. For this final rule, we have included by reference Docket ID No. EPA–HQ–OAR–2010–0505, Docket ID No. EPA–R08–OAR–2012–0479, Docket ID No. EPA–HQ–OAR–2003–0076, and Docket ID No. EPA–HQ–OAR–2014–0606 into Docket ID No. EPA–R08–OAR–2015–0709. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information for which disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available through *http://www.regulations.gov,* or please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section for additional availability information.

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SUPPLEMENTARY INFORMATION:

Definitions

Act or *CAA:* Clean Air Act, unless the context indicates otherwise.
AVO: Audio, Visual and Olfactory.
BTU: British Thermal Unit.
CBI: Confidential Business Information.
CEDRI: Compliance Emissions Data Reporting Interface.
CO: carbon monoxide.
EPA, we, us or *our:* The United States Environmental Protection Agency.
FBIR: Fort Berthold Indian Reservation.
FIP: Federal Implementation Plan.
GOR: gas-to-oil ratio.
HAP: hazardous air pollutants.
NAAQS: National Ambient Air Quality Standards.
NAICS: North American Industry Classification System.
NESHAP: National Emission Standards for Hazardous Air Pollutants.
NOx: nitrogen oxides.
NO_2: nitrogen dioxide.
NSPS: New Source Performance Standards.
NSR: New Source Review.
PM: particulate matter.
PSD: Prevention of Significant Deterioration.
PTE: potential to emit.
RIA: Regulatory Impact Analysis.
SCADA: Supervisory Control and Data Acquisition.
SIP: State Implementation Plan.
SO_2: sulfur dioxide.
TAR: Tribal Authority Rule.
TAS: treatment in a similar manner as a state.
TIP: Tribal Implementation Plan.
tpy: ton(s) per year
UDEQ: Utah Department of Environmental Quality.
U&O Reservation or the Reservation: The Uintah & Ouray Indian Reservation.
VOC: volatile organic compound(s).
VRU: vapor recovery unit.

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I. Executive Summary

A. Purpose of, and Agency Authority for, the Regulatory Action

We are finalizing this action using our authority under sections 301(a) and 301(d)(4) of the CAA and 40 CFR 49.11 to promulgate FIP provisions that are necessary and appropriate to protect air quality on the Indian country lands within the U&O Reservation and in nearby communities. The purpose of this U&O FIP is threefold.

First, and primarily, this U&O FIP will improve air quality on the U&O Reservation by addressing emissions from oil and natural gas production and natural gas processing activities on Indian country lands that contribute to the winter ozone problem in the physiographic region known as the Uinta Basin,[1] within which the U&O Reservation is located, and where ambient ozone levels have exceeded both the 2008 and the 2015 ozone NAAQS.[2] In 2018, the EPA designated portions of the Uinta Basin, including large portions of the Indian country lands within the U&O Reservation, as a Marginal nonattainment area for the 2015 ozone NAAQS.[3]

Air quality ozone monitoring data from the Uinta Basin in the years 2018, 2019 and 2020 indicates that the three-year average of the fourth maximum ambient air concentration measurements is 76 ppb, which violates the 2015 ozone NAAQS of 70 ppb. On April 13, 2022, the EPA proposed to grant a 1-year attainment date extension for the Uinta Basin Ozone Nonattainment area.[4] The proposal explains that preliminary 2021 ozone monitoring data indicate that the area may not attain the 2015 ozone NAAQS by the proposed extended attainment date of August 3, 2022, but that the area could meet the air quality criteria for a second 1-year extension. The Uinta Basin area's preliminary 2019–2021 design value was 78 ppb and the preliminary 2021 fourth highest daily maximum 8-hour concentration value was 72 ppb. To qualify for a second 1-year extension, an area's fourth highest daily maximum 8-hour value, averaged over both the original attainment year and the first extension year, must be 70 ppb or less. If the preliminary 2021 ozone data are certified, then the fourth highest daily maximum 8-hour value, averaged over 2020 and 2021, would be 69 ppb.[5]

The winter-time ozone formation in the Uinta Basin is caused by emissions of VOC and NO_X reacting in the presence of sunlight and widespread snow cover during temperature inversion conditions to form ground-level ozone at levels that exceed the ozone NAAQS and are therefore detrimental to public health. The main sources in the Basin responsible for VOC and NO_X emissions are existing oil and natural gas facilities. As explained in section III.D. (Air Quality and Attainment Status), most available information indicates that winter ozone formation in the Basin is driven by local emissions and is sensitive to changes in VOC emissions. There is greater uncertainty as to the sensitivity to changes in NO_X emissions. As explained in section III.E. (Emissions Information), available information indicates that 97 percent of anthropogenic VOC emissions in the Basin are from existing oil and natural gas activity, and that about 89 percent of those emissions are from existing sources on the Indian country lands within the U&O Reservation and in the nonattainment area. Before this rulemaking, VOC emissions control requirements for existing oil and natural gas sources existed in areas of the Basin where the EPA has approved the UDEQ to implement the CAA but did not exist in Indian country lands within the U&O Reservation. As explained in this final rulemaking and in the supporting information in the record, VOC control requirements are necessary to protect air quality on Indian country lands within the U&O Reservation.

The CAA does not require an attainment plan for Marginal ozone nonattainment areas.[6] Accordingly, this U&O FIP is not intended to bring the Uinta Basin back into attainment with the ozone standard. However, we do anticipate that this U&O FIP will make a meaningful improvement in air quality through the reduction of VOC, an ozone precursor, while also allowing continued construction authorization of new development in the Basin and the positive economic impact that this development brings to the Tribe.

This final action is driven by the EPA's authority and responsibility to protect air quality in Indian country under sections 301(a) and 301(d)(4) of the CAA and 40 CFR 49.11. Regarding preconstruction review of proposed new or modified sources [7] of air pollution in nonattainment areas in Indian country, the reviewing authority must demonstrate that the minor source or modification would not cause or contribute to a NAAQS violation in the nonattainment area (*see* 40 CFR 49.155(a)(7)(ii)) [8] and that preconstruction review of new major stationary sources and major

[1] For this rulemaking, the EPA defines the geographic scope of the Uinta Basin to be consistent with the Uinta Basin 2014 Air Agencies Oil and Gas Emissions Inventory (herein after referred to as the 2014 Uinta Basin Emissions Inventory), which encompasses Duchesne and Uintah counties. The 2014 Uinta Basin Emissions Inventory is available at: *https://deq.utah.gov/air-quality/2014-air-agencies-oil-and-gas-emissions-inventory-uinta-basin,* accessed Mar. 11, 2022.

[2] The 2015 ozone NAAQS is 70 parts per billion (ppb) (40 CFR 50.19). The 2008 ozone NAAQS is 75 ppb. Historical ozone NAAQS information is available at: *https://www.epa.gov/ozone-pollution/table-historical-ozone-national-ambient-air-quality-standards-naaqs,* accessed Mar. 11, 2022.

[3] On April 30, 2018, the EPA designated all of the Uinta Basin below a contiguous external perimeter of 6,250 ft. in elevation as a Marginal nonattainment area under the 2015 ozone NAAQS (83 FR 25776). This includes areas of the Basin where the EPA has approved the UDEQ to implement the CAA and Indian country lands within the U&O Reservation (where the EPA is promulgating this FIP). For more information, see *https://www.epa.gov/ozone-designations/additional-designations-2015-ozone-standards,* accessed Mar. 11, 2022.

[4] *See* 87 FR 21842 (Apr. 13, 2022), available at *https://www.govinfo.gov/content/pkg/FR-2022-04-13/pdf/2022-07513.pdf,* accessed Apr. 29, 2022.

[5] Additional details on the proposed extension of the attainment date are discussed in Section III.D. of this preamble.

[6] On March 9, 2018 (83 FR 10376), the EPA published the Classifications Rule, which established how the statutory classifications apply for the 2015 ozone NAAQS, including the air quality thresholds for each classification category. Based on this rule, each area with a 3-year design value of 71 ppb to 81 ppb, based on monitoring data from 2014–2016, was to be classified as a Marginal nonattainment area. The requirements for Marginal ozone nonattainment areas are specified in CAA Title I, Part D, subpart 2 (see 42 U.S.C. 7511a(a)) and include: (1) Comprehensive, accurate, current inventory of actual ozone precursor emissions from all sources; (2) Corrections, if necessary, to existing implementation plans to meet specific requirements, including for nonattainment major source permitting; (3) Triennial emissions inventory updates; and (4) General offset requirements for new and modified major sources.

[7] 40 CFR 49.152 defines ''minor modification at a major source,'' ''minor source,'' ''modification,'' ''synthetic minor source,'' and ''true minor source,'' all of which are subject to the permitting requirements of the Federal Minor New Source Review Program in Indian Country, at 40 CFR 49.151–49.165.

[8] 40 CFR 49.155 applies to your permit if you are subject to this program under 40 CFR 49.153(a) for construction of a new minor source, synthetic minor source or a modification at an existing source.

modifications to existing major stationary sources located in an area designated as nonattainment for any NAAQS would provide a net air quality benefit in the nonattainment area (*see* 40 CFR 49.169(b)(4)). While the CAA Indian country nonattainment permit program for *major* sources specifies offset requirements as the method to make such a demonstration (*see* 40 CFR 49.169(b)(3)), the CAA Indian country nonattainment permit program for *minor* sources is not prescriptive as to how to make such a demonstration. The requirements of this U&O FIP will result in VOC emission reductions from existing sources,[9] thereby improving air quality, and will also allow the EPA to rely on those reductions to meet the NAAQS protection requirements for continued construction authorization of new or modified minor sources in the nonattainment area.

This U&O FIP focuses on VOC emission reductions because improvements in winter ozone levels in the Basin are most likely to come from VOC emissions reductions from existing oil and natural gas sources.[10] Further, after a careful analysis of initial emissions data provided by industry and later updated using information obtained from two studies in the 2017 Uinta Basin Oil and Gas Emissions Inventory Update (referred to herein as the UBEI2017-Update),[11] we determined that most of the existing oil and natural gas sources on the Indian country lands within the U&O Reservation are largely uncontrolled for VOC and other emissions. Therefore, in developing this rule, we concentrated on determining the most effective control requirements to reduce VOC emissions from oil and natural gas sources to address the winter ozone exceedances. This is not to say that reductions in NO_X would not be beneficial in winter months. The EPA may decide to focus on NO_X reductions in future rulemakings if additional action is required to address air quality impacts from ozone pollution in the Basin.

Second, the control requirements being finalized are intended to be the same as or consistent with the requirements applicable to similar sources in areas of the Basin where the EPA has approved the UDEQ to implement the CAA, to promote a more consistent regulatory environment across the Basin. Where we are regulating existing equipment or activities that are also covered by EPA standards for the oil and natural gas source category, but do not meet the applicability criteria of those standards, we also strove for consistency with those EPA standards.

Finally, given the number of oil and natural gas projects in the Basin that are already approved or are in the federal review and approval process through evaluations conducted under the National Environmental Policy Act (NEPA) by other federal agencies,[12] in the coming years the EPA could receive a large number of applications for authorization to construct new and modified synthetic minor oil and natural gas sources on Indian country lands within the U&O Reservation, as well as registrations of new and modified true minor oil and natural gas sources on Indian country lands within the U&O Reservation under the Federal Implementation Plan for True Minor Sources in Indian Country in the Oil and Natural Gas Production and Natural Gas Processing Segments of the Oil and Natural Gas Sector (codified at 40 CFR part 49, subpart C, 40 CFR 49.101–49.105) [13] (National O&NG FIP). In addition to providing a streamlined construction authorization mechanism to new and modified true minor oil and natural gas sources,[14] the National O&NG FIP requires compliance with a suite of eight federal oil and natural gas source category emissions standards [15] for new and modified sources, as applicable. In 2019, the EPA extended the National O&NG FIP's streamlined construction authorization mechanism for true minor oil and natural gas sources in Indian country to the portions of the U&O Reservation within the Uinta Basin ozone nonattainment area.[16] We are relying on the existing source VOC emissions reductions that will be achieved under this U&O FIP to ensure that the limited extension of the National O&NG FIP to the Indian country portion of the Uinta Basin Ozone Nonattainment Area will not harm the area's ability to attain the NAAQS. This is described in greater detail in Sections V.C. and VI.B.

In the preamble to the final National O&NG FIP published on June 3, 2016, the EPA stated that the most appropriate means for addressing air quality concerns on specific reservations due to impacts from oil and natural gas activity is through area- or reservation-specific FIPs, not through the National O&NG FIP. Further, we stated that such FIPs may need to include requirements for existing, new, and modified sources

[9] Existing sources are sources that commence construction before the effective date of this FIP, per 40 CFR 49.4169(c).

[10] *See* Uinta Basin Ozone Studies (field studies conducted in the Basin from 2011 to 2014), available at *https://deq.utah.gov/air-quality/uinta-basin-ozone-studies-ubos,* accessed Mar. 11, 2022. The RIA for this rule contains detailed discussion of the studies and can be viewed in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

[11] *2017 Uinta Basin Oil and Natural Gas Emissions Inventory Update* (UBEI2017-Update). The inventory and supporting analysis can be viewed in the docket for this rule, Microsoft Excel spreadsheet titled, ''UO FIP cost and emissions analysis.xlsx'' (Docket ID No. EPA–R08–OAR–2015–0709). The inventory covers sources in Uintah and Duchesne Counties. The UDEQ submitted an earlier version of the 2017 inventory to the 2017 NEI and plans to submit the updated emissions at a future date. The UDEQ, the EPA, and the Ute Indian Tribe updated storage vessel, pneumatic controller, pneumatic pump, fugitive, gas well liquid unloading, blowdowns and pigging and oilfield wastewater emissions using updated emissions factors obtained from the Uinta Basin Composition Study and the acquisition of about 200 of oilfield wastewater (produced water) samples. The studies that updated the emissions factors are described in two White Papers available in the docket, ''UINTA BASIN VOC COMPOSITION STUDY IMPACTS ON THE 2017 OIL AND GAS EMISSIONS INVENTORY November 2020—Revised March 2021—White Paper'' (''DAQ–2021–004302.pdf''), and ''PRODUCED WATER DISPOSAL FACILITY EMISSION FACTORS & THEIR IMPACT ON THE 2017 OIL AND GAS EMISSIONS INVENTORY November 2020—Revised April 2021—White Paper'' (''DAQ–2020–016022.pdf'').

[12] Spreadsheet titled, ''Uinta Basin OG NEPA Evaluations 9.11.19.pdf,'' available in the Docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709), lists oil and natural gas production projects in the Uinta Basin that have been subject to evaluation under NEPA.

[13] Final Rule: Federal Implementation Plan for True Minor Sources in Indian Country in the Oil and Natural Gas Production and Natural Gas Processing Segments of the Oil and Natural Gas Sector; Amendments to the Federal Minor New Source Review Program in Indian Country to Address Requirements for True Minor Sources in the Oil and Natural Gas Sector, 81 FR 35944 (June 3, 2016); docket No. EPA–HQ–OAR–2014–0606, available at *https://www.regulations.gov,* accessed Mar. 11, 2022.

[14] As defined in the Federal Minor New Source Review Program in Indian Country at 40 CFR 49.152, a true minor source is a source that emits or has the potential to emit regulated NSR pollutants in amounts that are less than the major source thresholds in 40 CFR 49.167 (federal preconstruction permit program for major sources in nonattainment areas in Indian country) or 40 CFR 52.21 (federal preconstruction permit program for major sources in attainment/unclassifiable areas), as applicable, but equal to or greater than the minor NSR thresholds in 40 CFR 49.153 (federal preconstruction permit program for minor sources in Indian country), without the need to take an enforceable restriction to reduce its potential to emit to such levels.

[15] *See* 40 CFR 49.105. The National O&NG FIP specifies that sources must comply with, as applicable, the following standards: NESHAP 40 CFR part 63, subpart DDDDD; NESHAP 40 CFR part 63, subpart ZZZZ; NSPS IIII 40 CFR part 60, subpart IIII; NSPS 40 CFR part 60, subpart JJJJ; NSPS 40 CFR part 60, subpart Kb; NSPS 40 CFR part 60, subpart OOOOa; NESHAP 40 CFR part 63, subpart HH; and NSPS 40 CFR part 60, subpart KKKK.

[16] Final Rule: Amendments to Federal Implementation Plan for Managing Air Emissions from True Minor Sources in Indian Country in the Oil and Natural Gas Production and Natural Gas Processing Segments of the Oil and Natural Gas Sector, 84 FR 21240 (May 14, 2019); Docket No. EPA–HQ–OAR–2014–0606, available at *https://www.regulations.gov,* accessed Mar. 11, 2022.

beyond those in the National O&NG FIP.[17] Consistent with that approach, new and modified true minor oil and natural gas sources on Indian country lands within the U&O Reservation that would use the National O&NG FIP for construction authorization may have to comply with additional requirements for certain equipment or activities not covered by the eight federal standards.[18]

In summary, this U&O FIP is intended to: (1) improve air quality on Indian country lands within the U&O Reservation; (2) promote a more consistent regulatory environment across the Basin; and (3) ensure that emissions reductions will be achieved that will ensure that new development, under both source-specific minor source permitting and the National O&NG FIP's streamlined construction authorization mechanism for new or modified true minor oil and natural gas sources, will not interfere with attainment of the NAAQS.

B. Summary of the Major Provisions of This Final Rule

The following is a summary of each key requirement in the final action. As explained earlier, the final FIP was developed to maximize air quality improvement, in a manner that promotes a more consistent regulatory environment across all areas in the Uinta Basin, such that covered sources within Indian country on the U&O Reservation will be regulated in a manner similar to how they would be regulated if located in areas in the Basin where EPA has approved the UDEQ to implement the CAA. We attempted to achieve this goal by providing as much consistency as possible in the FIP with current federal standards for the oil and natural gas industry, including NSPS 40 CFR part 60, subparts OOOO and OOOOa (NSPS OOOO and OOOOa); NESHAP 40 CFR part 63, subpart HH (NESHAP HH); and the Control Techniques Guidelines for reducing smog-forming VOC emissions from existing oil and natural gas equipment and processes in certain states and areas with smog problems (Oil and Gas CTG).[19] The provisions in the final U&O FIP are informed by EPA's evaluation of these several applicable federal authorities as well as an evaluation of current UDEQ requirements that apply in the Uinta Basin outside of the Indian country lands within the U&O Reservation (areas of the Basin where the EPA has approved the UDEQ to implement the CAA). Where the EPA identified differences in these authorities, we considered the facts specific to the U&O Reservation in conjunction with the goals of the FIP to decide what to include in the final FIP. Our analysis was somewhat complicated by a recent joint resolution under the Congressional Review Act (CRA),[20] which disapproved policy revisions made in 2020 to NSPS OOOO and OOOOa [21] and thereby reinstated standards from the 2012 NSPS OOOO and 2016 NSPS OOOOa.[22] The resolution did not, however, disapprove technical revisions made in a separate rulemaking in 2020 to NSPS OOOOa,[23] which remain in place today. These two events resulted in regulatory inconsistencies between the NSPS OOOOa methane and VOC standards.[24] Further, the Oil and Gas CTG in some respects includes recommendations that do not match exactly with the requirements in the 2016 NSPS OOOOa methane standards.[25] In addition, the EPA recently proposed a rule to regulate methane and VOC emissions from existing, new, and modified sources in the oil and natural gas industry that would revise existing standards under NSPS OOOOa, establish new VOC and methane standards for emissions sources not previously covered by NSPS OOOOa, and establish methane emissions guidelines for existing sources (Oil and Natural Gas Sector Climate Review Proposed Rule).[26] As part of that proposed rule, the EPA addressed the inconsistencies between the methane and VOC standards in NSPS OOOOa by proposing to repeal certain NSPS OOOOa amendments that were made in the 2020 Technical Rule.[27] Despite these complications, EPA has focused its analysis for this U&O FIP on the currently applicable state and federal requirements and guidance.

That said, we acknowledge that the Agency's thinking on these issues has evolved since we issued NSPS OOOOa and the CTG in 2016. Among other developments, new information and analysis have been presented in the Oil and Natural Gas Sector Climate Review Proposed Rule that will likely be relevant for reducing emissions on the U&O Reservation. When the EPA proposed this FIP, however, the Agency had not yet proposed that other rule, and the Climate Review Rule is still being developed. In the interest of moving quickly to achieve emissions reductions, the EPA finds that it is necessary and appropriate to finalize this FIP now. Our assessment of new, potentially relevant information will continue in the context of the Oil and Natural Gas Sector Climate Review Rule. If we finalize that proposed national rule in the future, its

[17] *See* 81 FR 35964, 35968.

[18] As described in detail later, this action exempts certain equipment and activities that are subject to the emissions control requirements of a subset of the eight federal standards in the National O&NG FIP from having to comply with the emissions control requirements in this action for the same equipment and activities. Other types of equipment, such as small and remote glycol dehydrators and storage vessels with potential emissions ≤ 6 tpy VOC, are not regulated by those federal standards but are regulated in this action.

[19] Available at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/2016-control-techniques-guidelines-oil-and,* accessed Mar. 11, 2022. CTGs are not regulations and do not impose legal requirements directly on pollution sources; rather, they provide recommendations for state and local air agencies to consider as they determine what emissions limits to apply to covered sources in their jurisdictions in order to meet RACT requirements.

[20] 5 U.S.C. 801–808.

[21] 85 FR 57018 (Sept. 14, 2020) (''2020 Policy Rule''; as of June 30, 2021, no longer in effect due to CRA disapproval).

[22] Public Law 17–23 (June 30, 2021) (resolving that Congress ''disapproves the [2020 Policy Rule] . . . and such rule shall have no force or effect'').

[23] 85 FR 57398 (Sept. 15, 2020) (''2020 Technical Rule'').

[24] For requirements that currently apply, see *Congressional Review Act Resolution to Disapprove EPA's 2020 Oil and Gas Policy Rule. Questions and Answers.* U.S. Environmental Protections Agency. Office of Air Quality Planning and Standards. June 30, 2021, available at *https://www.epa.gov/system/files/documents/2021-07/qa_cra_for_2020_oil_and_gas_policy_rule.6.30.2021.pdf,* accessed Mar. 11, 2022.

[25] For example, while the CTG recommends exempting low-production well sites from monitoring fugitive VOC emissions, the current OOOOa methane standards do not have such exemption.

[26] *Proposed Rule. Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. See* 86 FR 63110, November 15, 2021, available at *https://www.regulations.gov* (Document ID No. EPA–HQ–OAR–2021–0317–0001), accessed Mar. 14, 2022. On the same day that this action is being signed, the Administrator has also signed a supplemental notice which proposes to update and expand on the 2021 Climate Review proposal. See *Supplemental notice of proposed rulemaking. Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review.* Signed by the EPA Administrator on November 8, 2022, available at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-issues-supplemental-proposal-reduce.* Today's action discusses certain aspects of the 2021 Climate Review proposal, but does not attempt to describe the 2022 supplemental proposal, in light of the concurrent signature of the latter action.

[27] For example, the EPA is proposing to repeal the 2020 Technical Rule amendments that exempted low-production well sites from monitoring fugitive VOC emissions, and those that changed fugitive VOC emissions monitoring requirements at gathering and boosting compressor stations from quarterly to semi-annually. The proposed rule would also establish an LDAR applicability threshold for existing, new, and modified oil and natural gas well sites of 3 tpy site-wide methane fugitive emissions (and co-proposed an alternative threshold of 8 tpy site-wide methane fugitive emissions).

requirements will apply directly to covered sources. As to sources not covered by a final national rule, the EPA may find it necessary or appropriate to revisit this final action in the future and revise this FIP based on information evaluated in issuance of a final Climate Review Rule, providing public notice of the opportunity for review and comment on any such revisions as part of the required rulemaking process. Also, if the Uinta Basin Ozone Nonattainment Area's Marginal classification is reclassified (''bumped up'') to a Moderate nonattainment classification, or if air quality concerns otherwise warrant, we may conclude that further rulemaking is necessary or appropriate.

General applicability: The final rule applies to owners or operators of oil and natural gas sources that produce oil and natural gas or process natural gas, that are located on Indian country lands within the U&O Reservation, and that meet the applicability criteria specified for each set of requirements. The final rule is effective 60 days after the date of publication in the **Federal Register**. For new and modified sources that construct on or after the effective date of this final rule, compliance is required upon startup. Compliance for existing sources that commence construction before the effective date of the final rule is required no later than 12 months after the effective date of the final rule. The final rule allows owners or operators to request approval, on a case-specific basis and prior to the compliance deadline, of an extension of the compliance deadline for existing sources.

Delegation of authority of administration to the Tribe: The final rule contains provisions for the Ute Indian Tribe to request delegation to assist the EPA with administration of the federal rule and the process by which the EPA may delegate such authority.

Emissions inventory: The final rule requires that each owner and operator of affected oil and natural gas sources with the potential to emit one or more NSR-regulated pollutants at levels greater than or equal to 1 tpy must submit an inventory of actual emissions for each emissions unit to the EPA every three years that covers emissions from the previous calendar year (OMB Control No. 2008—New (2539.02)). The emissions inventory serves the purpose of the triennial collection of comprehensive Uinta Basin oil and natural gas emissions by the EPA, the Ute Indian Tribe, and UDEQ, and corresponds with the years that emissions inventory information is collected for the EPA National Emissions Inventory (NEI).[28]

Storage vessels, glycol dehydrators and pneumatic pumps: The final rule contains federally enforceable requirements for owners and operators of each existing, new, and modified oil and natural gas source that has the potential to emit 4 tons per year of VOC or more from the collection of all storage vessels, glycol dehydrators and pneumatic pumps. The rule requires that each affected oil and natural gas source collect and route all VOC emissions from each storage vessels, glycol dehydrator and pneumatic pump through a closed-vent system to an operating system designed to recover 100 percent of the emissions and recycle them for use in a process unit or incorporate them into a product, or route them to a flare or other control device designed and operated to achieve at least 95.0 percent continuous VOC emissions control efficiency.

Covers and closed-vent systems: The final rule requires owners and operators of affected existing, new, and modified oil and natural gas sources that are required to control VOC emissions from the collection of all storage vessels, glycol dehydrators and pneumatic pumps, to: use covers on any affected storage vessels that ensure flashing, working, standing, and breathing losses are efficiently captured; and to capture and route emissions from any affected storage vessel, glycol dehydrator and pneumatic pump through closed-vent systems with equipment that ensures all VOC emissions make it to the respective process or VOC emissions control device. The rule contains construction and operational requirements that are intended to provide legal and practicable enforceability to ensure that all captured emissions are routed to their intended destination with no detectable emissions.

Control devices: The final rule contains legally and practicably enforceable construction, work practice, and operational requirements for each required flare or enclosed combustor. Each flare must be designed and operated according to the requirements of 40 CFR 60.18(b). Each enclosed combustor must be designed and operated to reduce the mass content of the VOC in the natural gas routed to it by at least 95.0 percent on a continuous basis, and must be tested by the manufacturer, owner, or operator in accordance with the requirements of 40 CFR part 60 subparts OOOO or OOOOa. Flares and enclosed combustors must be operated within specific parameters to ensure the effective control of VOC emissions (including requirements to be equipped and operated with a liquid knockout system, a continuously burning pilot flame or electronically controlled automatic ignition device, and a monitoring system for continuous monitoring and recording of operational parameters; maintained in a leak-free condition; and operated with no visible smoke emissions).

Fugitive emissions: The final rule requires implementation of a semi-annual leak detection and repair (LDAR) program for the collection of fugitive emissions components at each oil and natural gas source with facility-wide potential emissions from the collection of all storage vessels, glycol dehydrators and pneumatic pumps equal to or greater than 4 tpy VOC, plus any additional well sites with production of more than 15 barrels of oil equivalent (boe) per day.[29] The final rule also contains provisions allowing for the use of alternative methods of leak detection, provided the method is approved by the EPA.

VOC emissions control requirements for all sources: The final rule contains VOC control requirements for all existing, new, and modified oil and natural gas sources, regardless of source-wide or emission unit specific

[28] Information available at *https://www.epa.gov/air-emissions-inventories/national-emissions-inventory-nei,* accessed Mar. 11, 2022.

[29] As explained earlier, this FIP has been developed to maximize air quality improvements in a manner that promotes a more consistent regulatory environment across jurisdictional boundaries. We evaluated several authorities to further these goals with respect to fugitive emissions monitoring. The Oil and Gas CTG does not recommend that well sites with production of less than 15 boe per day (''low-production'' well sites) monitor fugitive emissions. Using a different measure, the UDEQ applies LDAR requirements only at well sites where the total actual uncontrolled VOC emissions from the collection of storage vessels and glycol dehydrators is greater than or equal to 4 tpy VOC (unless the well site is subject to the LDAR requirements of NSPS OOOOa, in which case the operator would comply with NSPS OOOOa).And as explained above, the NSPS OOOOa requirements may be changed by the Oil and Natural Gas Sector Climate Review Proposed Rule, which proposes to repeal some of the amendments that were made to NSPS OOOOa as part of the 2020 Technical Rule. Among the provisions proposed for repeal are those that exempted low-production well sites from fugitive emissions monitoring and those that changed fugitive VOC monitoring requirements at gathering and boosting compressor stations from quarterly to semi-annually. Those fugitive VOC standards are still in place today, and are in contrast to the 2016 fugitive methane standards that were reinstated by the CRA disapproval of the 2020 Policy Rule. The proposed rule also would require quarterly monitoring at oil and natural gas well sites of 3 tpy site-wide methane fugitive emissions (and co-proposes semi-annual monitoring for those with site-wide methane fugitive emissions between 3 and 8 tpy, with quarterly monitoring for those with site-wide methane fugitive emissions above 8 tpy).

applicability criteria. These requirements include: (1) tank trucks transporting crude oil, condensate, intermediate hydrocarbon liquids or produced water must be loaded using bottom filling or submerged fill pipes; (2) all existing pneumatic controllers must meet the pneumatic controller standards in NSPS OOOO; and (3) all existing enclosed combustors and flares present and operating at sources on a voluntary basis must be equipped with an electronically controlled automatic ignition device.

Monitoring, recordkeeping, notification and reporting: This U&O FIP requires owners or operators to conduct source monitoring sufficient to demonstrate compliance with the FIP's VOC emission reduction and control requirements, including: (1) monthly inspections of each cover and closed-vent system to ensure proper condition and functioning and to identify defects that can result in air emissions, correcting or repairing any defects identified within 30 days of identification; and (2) monthly inspections of each VOC emissions control device to ensure proper functioning whenever an operator is on site, at least once per calendar month, and responding to any indication of malfunction (*e.g.,* pilot flame failure, visible emissions) as soon as practicably and safely possible after discovery.

C. Costs and Benefits

The EPA has projected the compliance costs, emissions reductions, and benefits that may result from the U&O FIP. The discussion of projected costs and benefits is presented in detail in the Regulatory Impacts Analysis (RIA) accompanying this final rule.[30] The RIA focuses on the elements of the final rule—the provisions related to VOC emissions control requirements—that are likely to result in quantifiable costs, emissions changes, and benefits compared to a baseline that includes operator-reported emissions from oil and natural gas sources in the Uinta Basin for calendar year 2017, specifically on the Indian country lands within the U&O Reservation. We estimated the effects of the final rule for all sources that are conservatively projected[31] to be subject to compliance activities under this action for the analysis years 2023 through 2032. The RIA also presents the present value (PV) and equivalent annualized value (EAV) of costs, benefits and net benefits of this action in 2016 dollars.

A summary of the key results of this final rule is presented in Table 1. Table 1 presents the PV and EAV, estimated using discount rates of 7 and 3 percent, of the benefits, costs and net benefits, as well as the change in emissions under the final rule. The monetized net benefits are the benefits (emissions reductions) minus the costs (annualized compliance costs). These results present an incomplete overview of the effects of the final FIP, because categories of benefits—including benefits from reducing other types of air pollutants—were not monetized and are therefore not reflected in Table 1.

TABLE 1—BENEFITS, COSTS, NET BENEFITS AND EMISSIONS REDUCTIONS OF THE FINAL RULE 2023 THROUGH 2032

[Dollar estimates in millions of 2016 dollars][a]

	Present value	Equivalent annual value	Present value	Equivalent annual value
3 Percent Discount Rate				
Benefits[b]	$1,000	$120	$1,000	$120
	3 Percent Discount Rate		7 Percent Discount Rate	
Net Compliance Costs	610	72	560	81
Compliance Costs	630	74	580	83
Product Recovery	20	2	20	2
Net Benefits	390	48	440	39
Non-Monetized Benefits[c]	Ozone health and climate benefits from reducing 23,000 tons of VOC/year and ozone health benefits from 59,000 tons of methane/year from 2023 to 2032.			
	Ozone health and $PM_{2.5}$ benefits from reducing 23,000 tons of VOC/year from 2023 to 2032.			
	HAP benefits from reducing 3,100 tons of HAP/year from 2023 to 2032 (including 570 tons of benzene, 970 tons of toluene, 130 tons of ethylbenzene, 620 tons of xylenes and 770 tons of n-hexane per year).			
	Visibility benefits.			
	Reduced vegetation effects from exposure to ozone.			

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

[30] Available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

[31] As explained throughout this preamble, and in the RIA, this quantitative projection does not account for those sources that may be exempt from certain requirements of the rule because they are subject to equivalent requirements in NSPS OOOO or OOOOa, or in NESHAP HH. Therefore, it is likely that costs for those sources will be less for certain activities than for sources subject to requirements of the FIP.

[b] Monetized benefits of the final rule include climate benefits associated with reductions in methane emissions and are calculated using four different estimates of the social cost of methane (SC–CH_4) (model average at 2.5 percent, 3 percent, and 5 percent discount rates: 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average SC–CH_4 at a 3 percent discount rate, but the Agency does not have a single central SC–CH_4 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC–CH_4 estimates; the present value (and equivalent annual value) of the additional benefit estimates (millions of 2016$) ranges from $480 to $2,700 ($62 to $310) over 2023 to 2032 for the final rule. Please see Table 6–6 of the RIA for the full range of SC–CH_4 estimates. As discussed in Section 6.5 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. All net benefits are calculated using climate benefits discounted at 3 percent.

[c] There are important unquantified health and welfare benefits associated with reductions in other air pollutants, which are discussed in Chapter 6 of the RIA.

This final rule is expected to result in net benefits (emissions reductions) for human health and the environment in the Uinta Basin. The estimated benefits include the monetized climate effects of the projected reduction in methane emissions under the final rule resulting from the targeted reduction of VOC emissions. The PV of these climate-related benefits (emissions reductions), discounted at a 3-percent rate, is estimated to be about $1 billion, with an EAV of about $120 million (Table 1).

In addition to directly controlling VOC emissions, which are expected to lower ozone concentrations in the Uinta Basin, this action is expected to lower HAP emissions and the formation of secondary particulate matter with a diameter of 2.5 micrometers or less ($PM_{2.5}$) even though those pollutants are not directly regulated under this action. While the EPA expects that the VOC emissions reductions will improve air quality and have beneficial health and welfare effects associated with reduced exposure to ozone, $PM_{2.5}$, and HAP, we did not quantify those effects. We note that the absence of those monetized benefits from the analysis of benefits does not imply that these benefits do not exist, but also has no bearing on the legal or technical basis for the final action itself. We qualitatively discuss these unquantified benefits in Chapter 6 of the RIA. If the EPA were to quantify the ozone and $PM_{2.5}$ impacts, the Agency would estimate the number and value of avoided premature deaths and illnesses using an approach detailed in the Particulate Matter NAAQS and Ozone NAAQS RIA.[32] Such an analysis would account for the distribution of air pollution-attributable risks among populations most vulnerable and susceptible to $PM_{2.5}$ and ozone exposure. As explained in the RIA for this final rule, due to methodology and data limitations for areas experiencing elevated winter ozone, we were unable to estimate the benefits associated with ozone, $PM_{2.5}$, and HAP emission changes that would occur as a result of this rule, but the EPA continues to develop better methods for analyzing the benefits of such reductions.

The estimated capital and annualized compliance costs include the monetized costs for affected owners or operators to comply with the final rule. The net PV of these compliance costs (accounting for product recovery), discounted at a 7-percent rate, is estimated to be about $560 million, with an EAV of about $81 million (Table 1). Under a 3-percent discount rate, the PV of the compliance costs is about $610 million, with an EAV of about $72 million (Table 1).

The PV of the net benefits of this rule, discounted at a 7-percent rate, is estimated to be about $440 million, with an EAV of about $39 million (Table 1). Under a 3-percent discount rate, the PV of net benefits is about $390 million, with an EAV of about $48 million (Table 1).

II. General Information

A. Does this action apply to me?

Entities potentially affected by this rule include the Ute Indian Tribe,[33] as well as existing, new, and modified sources[34] that are in the oil and natural gas production and natural gas processing segments of the oil and natural gas industry (see Table 2.) and are on Indian country[35] lands within the U&O Reservation. All of the Ute Indian Tribe Indian country lands of which the EPA is aware are located within the exterior boundaries of the Reservation, and this U&O FIP applies to all such lands. To the extent that there are Ute Indian Tribe Dependent Indian Communities under 18 U.S.C. 1151(b) or allotted lands under 18 U.S.C. 1151(c) that are located outside the exterior boundaries of the Reservation, those lands are not covered by this U&O FIP.[36] In addition, this rule does not apply to any sources on non-Indian-country lands, including any non-Indian country lands within the exterior boundaries of the Reservation.[37]

[32] U.S. EPA. Integrated Science Assessment (ISA) for Particulate Matter (Final Report). EPA Office of Research and Development (ORD), National Center for Environmental Assessment, EPA/600/R–19/188 (Dec. 2019); available at: *https://www.epa.gov/naaqs/particulate-matter-pm-standards-integrated-science-assessments-current-review,* accessed Mar. 11, 2022, and U.S. EPA. Integrated Science Assessment for Ozone and Related Photochemical Oxidants. EPA ORD, EPA/600/R–20/012 (Apr. 2020); available at: *https://www.epa.gov/isa/integrated-science-assessment-isa-ozone-and-related-photochemical-oxidants.* Accessed Mar. 11, 2022.

[33] The Ute Indian Tribe is a federally recognized tribe organized under the Indian Reorganization Act of 1934, with a Constitution and By-Laws adopted by the Tribe on December 19, 1936 and approved by the Secretary of the Interior on January 19, 1937. *See* Indian Entities Recognized and Eligible to Receive Services from the United States Bureau of Indian Affairs, *See* 82 FR 4915 (Jan. 17, 2017); 48 Stat. 984, 25 U.S.C.5123 (IRA); Constitution and By-Laws of the Ute Indian Tribe of the Uintah and Ouray Reservation.

[34] As specified at 40 CFR 49.4169(c).

[35] Indian country is defined at 18 U.S.C. 1151 as: (a) all land within the limits of any Indian reservation under the jurisdiction of the United States Government, notwithstanding the issuance of any patent, and, including rights-of-way running through the reservation, (b) all dependent Indian communities within the borders of the United States whether within the original or subsequently acquired territory thereof, and whether within or without the limits of a state, and (c) all Indian allotments, the Indian titles to which have not been extinguished, including rights-of-way running through the same.

[36] Under the CAA, lands held in trust for the use of an Indian tribe are reservation lands within the definition at 18 U.S.C.1151(a), regardless of whether the land is formally designated as a reservation. *See* Indian Tribes: Air Quality Planning and Management, *See* 63 FR 7254, 7258 (Feb. 12, 1998) (''Tribal Authority Rule''); *Arizona Pub. Serv. Co.* v. *EPA,* 211 F.3d 1280, 1285–86 (D.C. Cir. 2000). The EPA's references in this U&O FIP to Indian country lands within the exterior boundaries of the U&O Reservation include any such Tribal trust lands that may be acquired by the Ute Indian Tribe.

In 2014, the U.S. Court of Appeals for the D.C. Circuit addressed the EPA's authority to promulgate a FIP establishing certain CAA permitting programs in Indian country. *Oklahoma Dept. of Environmental Quality* v. *EPA,* 740 F. 3d 185 (D.C. Cir. 2014). In that case, the court recognized the EPA's authority to promulgate a FIP to directly administer CAA programs on Indian reservations but invalidated the FIP at issue as applied to non-reservation areas of Indian country in the absence of a demonstration of an Indian tribe's jurisdiction over such non-reservation area. Because the final rule would apply only on Indian country lands that are within the exterior boundaries of the U&O Reservation, *i.e.,* on Reservation lands, it is unaffected by the *Oklahoma* court decision.

[37] As a result of a series of federal court decisions, there are some non-Indian country lands within the exterior boundaries of the Uintah and Ouray Indian Reservation. *See* footnote 40.

TABLE 2—SOURCE CATEGORIES AFFECTED BY THIS ACTION

Industry category	NAICS code	Examples of regulated entities/description of industry category
Oil and Gas Production/Operations	21111	Exploration for crude petroleum and natural gas; drilling, completing, and equipping wells; operation of separators, emulsion breakers, desilting equipment, and field gathering lines for crude petroleum and natural gas; and all other activities in the preparation of oil and gas up to the point of shipment from the producing property. Production of crude petroleum, the mining and extraction of oil from oil shale and oil sands, the production of natural gas, sulfur recovery from natural gas, and the recovery of hydrocarbon liquids from oil and gas field gases.
Crude Petroleum and Natural Gas Extraction.	211111	Exploration, development and/or the production of petroleum or natural gas from wells in which the hydrocarbons will initially flow or can be produced using normal pumping techniques or production of crude petroleum from surface shales or tar sands or from reservoirs in which the hydrocarbons are semisolids
Natural Gas Liquid Extraction	211112	Recovery of liquid hydrocarbons from oil and gas field gases; and sulfur recovery from natural gas.
Drilling Oil and Gas Wells	213111	Drilling oil and gas wells for others on a contract or fee basis, including spudding in, drilling in, redrilling, and directional drilling.
Support Activities for Oil and Gas Operations.	213112	Performing support activities on a contract or fee basis for oil and gas operations (except site preparation and related construction activities) such as exploration (except geophysical surveying and mapping); excavating slush pits and cellars, well surveying; running, cutting, and pulling casings, tubes, and rods; cementing wells, shooting wells; perforating well casings; acidizing and chemically treating wells; and cleaning out, bailing, and swabbing wells.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that the EPA is now aware could potentially be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your entity is regulated by this action, you should carefully examine the applicability criteria found in 40 CFR 49.4169 through 49.4184. If you have any questions regarding the applicability of this action to a particular entity, contact the appropriate person listed in the **FOR FURTHER INFORMATION CONTACT** section.

B. 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 final action will also be posted at: *https://www.epa.gov/air-quality-implementation-plans/approved-air-quality-implementation-plans-region-8* (Approved Air Quality Implementation Plans in Region 8 page).

C. Judicial Review

Under section 307(b)(1) of the Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by February 6, 2023. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed and shall not postpone the effectiveness of such rule or action. Under section 307(b)(2) of the Act, the requirements of this final action with respect to which review could have been obtained under section 307(b)(1) of the Act may not be judicially reviewed later in civil or criminal proceedings brought by us to enforce these requirements.

III. Background

A. Uintah and Ouray Indian Reservation

The Uintah and Ouray Indian Reservation is composed of lands that were part of the original Uintah Valley and Uncompahgre Reservations, which were established by executive order in 1861 and 1882, respectively.[38] In 1948 Congress extended the exterior boundary of the Reservation with the Hill Creek Extension.[39] The U&O Reservation's boundaries have been addressed and explained in a series of federal court decisions. Consistent with those decisions, the EPA considers all lands within the U&O Reservation's boundaries to be ''Indian country'' as defined in 18 U.S.C. 1151, subject to federal court decisions holding that specified Congressional acts removed certain lands from Indian country status.[40]

B. Tribal Authority Rule

Section 301(d) of the CAA authorizes the EPA to treat Indian tribes in the same manner as states for purposes of implementing the CAA over their entire reservations and over any other areas within their jurisdiction, and directs the EPA to promulgate regulations specifying those provisions of the CAA for which such treatment is appropriate.[41] It also authorizes the EPA, when the EPA determines that the treatment of Indian tribes as identical to states is inappropriate or administratively infeasible, to provide by regulation other means by which the EPA will directly administer the CAA.[42] Acting principally under that authority, on February 12, 1998, the EPA promulgated the Tribal Authority Rule (TAR).[43] In the TAR, we determined that it was appropriate to treat eligible tribes in the same manner as states for

[38] *See* Exec. Order of Oct. 3, 1861, reprinted in 1 Charles J. Kappler, Indian Affairs: Laws and Treaties 900 (1904); confirmed by Congress in the Act of May 5, 1864, ch. 77, 13 Stat. 63; Exec. Order of Jan. 5, 1882, reprinted in Indian Affairs: Laws and Treaties at 901; U.S. Office of Indian Affairs, Dept. of the Interior, Annual Report of the Commissioner of Indian Affairs, at 226 (1886).

[39] 62 Stat. 72 (1948).

[40] *See Ute Indian Tribe* v. *Utah,* 521 F. Supp. 1072 (D. Utah 1981); *Ute Indian Tribe* v. *Utah,* 716 F.2d 1298 (10th Cir. 1983); *Ute Indian Tribe* v. *Utah,* 773 F.2d 1087 (10th Cir. 1985) (en banc), *cert. denied,* 479 U.S. 994 (1986); *Hagen* v. *Utah,* 510 U.S. 399 (1994); *Ute Indian Tribe* v. *Utah,* 935 F. Supp. 1473 (D. Utah 1996); *Ute Indian Tribe* v. *Utah,* 114 F.3d 1513 (10th Cir. 1997), *cert. denied,* 522 U.S. 1107 (1998); *Ute Indian Tribe* v. *Utah,* 790 F.3d 1000 (10th Cir. 2015), *cert. denied,* 136 S. Ct. 1451 (2016); and *Ute Indian Tribe* v. *Myton,* 835 F.3d 1255 (10th Cir. 2016), *cert. dismissed,* 137 S. Ct. 2328 (2017); *Hackford* v. *Utah,* 845 F.3d 1325, 1327 (10th Cir.), cert. denied, 138 S. Ct. 206 (2017).

[41] 42 U.S.C. 7601(d)(1) and (2); *See* 63 FR 7254–57 (Feb. 12, 1998) (explaining that CAA section 301(d) includes a delegation of authority from Congress to eligible Indian tribes to implement CAA programs over all air resources within the exterior boundaries of their Reservations).

[42] 42 U.S.C. 7601(d)(4).

[43] ''Indian Tribes: Air Quality Planning and Management.'' *see* 63 FR 7254 (Feb. 12, 1998); 40 CFR 49.1–49.11.

all CAA statutory and regulatory purposes, except a list of specified CAA provisions and implementing regulations thereunder.[44] That list of excluded provisions includes specific plan submittal and implementation deadlines for NAAQS-related requirements, among them the CAA section 110(a)(2)(C) requirement to submit a program (including a permit program as required in parts C and D of the CAA) to regulate the modification and construction of any stationary source as necessary to assure that the NAAQS are achieved. Other provisions for which we determined that we would not treat tribes in the same manner as states include CAA section 110(a)(1) (SIP submittal) and CAA section 110(c)(1) (directing the EPA to promulgate a FIP ''within 2 years'' after we find that a state has failed to submit a required plan or has submitted an incomplete plan, or within 2 years after we disapprove all or a portion of a plan).

The TAR preamble clarified that by including CAA section 110(c)(1) on the list at 40 CFR 49.4, the ''EPA is not relieved of its general obligation under the CAA to ensure the protection of air quality throughout the nation, including throughout Indian country.'' [45] The preamble confirmed that the ''EPA will continue to be subject to the basic requirement to issue a FIP for affected tribal areas within some reasonable time.'' [46] Consistent with those statements, the TAR includes a provision requiring the EPA to ''promulgate without unreasonable delay such Federal implementation plan provisions as are necessary or appropriate to protect air quality,'' unless a complete TIP is submitted or approved.[47]

The Ute Indian Tribe has not applied for treatment in a similar manner as a state (TAS) for the purpose of administering a TIP under the CAA; nor has it submitted a TIP for review and approval. Thus, with respect to Indian country lands within the U&O Reservation, there is currently no submitted or EPA-approved TIP that would address the air quality purposes described earlier. This FIP provides such a plan and applies to all Indian country lands within the exterior boundaries of the U&O Reservation.

C. Federal Indian Country Minor NSR Rule

1. What is the Federal Indian Country Minor NSR rule?

In 2006, acting under the authority provided in CAA section 301(d) and in the TAR, we proposed the FIP regulation: ''Review of New Sources and Modifications in Indian Country'' (Indian Country NSR rule).[48] As a part of this regulation, the EPA made a finding that it was necessary or appropriate to protect air quality by developing a FIP to establish a program to regulate the modification and construction of minor stationary sources consistent with the requirements of section 110(a)(2)(c) of the CAA, where there was no EPA-approved tribal minor NSR permit program in Indian country to regulate construction of new and modified minor sources and minor modifications of major sources. We call this part of the Indian Country NSR rule the Federal Indian Country Minor NSR rule. In developing that FIP, we sought to ''establish a flexible preconstruction permitting program for minor sources in Indian country that is comparable to similar programs in neighboring states in order to create a more consistent regulatory environment for owners/operators within and outside of Indian country.'' [49] The Federal Indian Country Minor NSR rule provides a mechanism for issuing preconstruction permits for the construction of new minor sources and certain modifications of major and minor sources in areas covered by the rule. In developing the rule, the EPA conducted extensive outreach and consultation, along with a 7-month public comment period that ended on March 20, 2007. The comments provided detailed information specific to Indian country, and the final Federal Indian Country Minor NSR rule incorporated many of the suggestions we received. We promulgated a final rule on July 1, 2011, and the FIP became effective on August 30, 2011. [50]

The Federal Indian Country Minor NSR rule applies to existing, new, and modified minor stationary sources and to minor modifications at existing major stationary sources in Indian country where there is no EPA-approved program in place. [51] Tribes can elect to develop and implement their own EPA-approved program under the TAR but are not required to do so.[52] In the absence of an EPA-authorized program, the EPA implements the program. Tribes can request administrative delegation of the federal program from the EPA and may be authorized by the EPA to implement agreed-upon rules or provisions on behalf of the Agency.

Any existing, new, or modified stationary oil and natural gas source that emits or has the potential to emit (PTE) a regulated NSR pollutant in amounts equal to or greater than the minor NSR thresholds in the Federal Indian Country Minor NSR rule, but less than the amount that would qualify the source as a major source or a major modification for purposes of the PSD or nonattainment major NSR programs, must submit a registration form to the EPA containing information on, among other things, source-wide actual emissions of NSR regulated pollutants, information on the methods used to calculate the emissions, and descriptions of the various emitting activities and equipment operated at the source. Existing, new, and modified oil and natural gas sources that commenced construction before October 3, 2016, complied with the Federal Indian Country Minor NSR Permit Program by registering under the Existing Source Registration Program at 40 CFR 49.160. Beginning October 3, 2016, the owner/operator of any new true minor oil and natural gas source must comply with the National O&NG FIP or apply for and obtain a site-specific true minor NSR permit before beginning construction. Likewise, the owner/operator of any existing stationary source (minor or major) must comply with the National O&NG FIP or apply for and obtain a minor NSR permit before beginning construction of a physical or operational

[44] 40 CFR 49.3–.4. To be eligible for treatment in a similar manner as a state (TAS) under the Tribal Authority Rule, a tribe must meet four requirements: (1) be a federally recognized tribe; (2) have a governing body carrying out substantial governmental duties and functions; (3) propose to carry out functions pertaining to the management and protection of air resources of the tribe's reservation or other areas within the tribe's jurisdiction; and (4) be reasonably expected to be capable of carrying out the functions. 40 CFR 49.6. A tribe interested in administering a particular CAA program or function may apply to the appropriate regional administrator for a determination of whether it meets these TAS eligibility criteria with respect to that program or function. 40 CFR 49.7.

[45] *See* 63 FR at 7265 (Feb. 12, 1998).

[46] Id.

[47] 40 CFR 49.11(a).

[48] ''Review of New Sources and Modifications in Indian Country,'' Proposed Rule, 71 FR 48696 (Aug. 21, 2006).

[49] ''Review of New Sources and Modifications in Indian Country,'' Final Rule, 76 FR 38748, 38754 (July 1, 2011).

[50] *See* 76 FR 38748.

[51] 40 CFR 49.153. Existing sources are only subject to the registration requirements unless they undergo modification.

[52] To be eligible to develop and implement an EPA-approved program, under the Tribal Authority Rule a tribe must meet four requirements: (1) be a federally-recognized tribe; (2) have a functioning government carrying out substantial duties and powers; (3) propose to carry out functions pertaining to air resources of the reservation or other areas within the tribe's jurisdiction; and (4) be reasonably expected to be capable of carrying out the program. *See* 40 CFR 40 CFR 49.1–49.11. Tribes can also establish permit fees under a tribal permitting program pursuant to tribal law, as do most states.

change that will increase the allowable emissions of the stationary source in amounts equal to or above the specified threshold amounts, if the change does not otherwise trigger PSD or nonattainment major or minor NSR permitting requirements.[53]

2. What are the minor NSR thresholds?

The ''minor NSR thresholds'' establish cutoff levels for each regulated NSR pollutant. If a source has a PTE in amounts lower than the minor NSR thresholds,[54] then it is exempt from the Federal Indian Country Minor NSR rule for that pollutant. New or modified sources that have a PTE in amounts that are: (1) equal to or greater than the minor NSR thresholds; and (2) less than the major NSR thresholds (generally 100 or 250 tons per year (tpy)) are ''minor sources'' of emissions and subject to the Federal Indian Country Minor NSR rule requirements at 40 CFR 49.151 through 49.161. Modifications at existing major sources that have PTE equal to or greater than the minor NSR thresholds, but less than the major NSR significant emission rates (range 10–100 tpy, depending on the pollutant) are also ''minor sources'' of emissions and subject to the Federal Indian Country Minor NSR rule requirements.

The minor NSR thresholds for VOC emissions for sources in Indian country are 2 tpy in nonattainment areas and 5 tpy in attainment and unclassifiable areas. Portions of the U&O Reservation are currently designated unclassifiable for the 2008 ozone NAAQS and the minor NSR thresholds for VOC are 5 tpy in those Indian country portions of the Reservation. As discussed previously and further in Section D (Air Quality and Attainment Status), other portions of the U&O Reservation are included in the Uinta Basin Ozone Nonattainment Area, and, therefore, the minor NSR thresholds for VOC are 2 tpy in those Indian country portions of the Reservation.

D. Air Quality and Attainment Status

With respect to air quality, ozone levels in the Uinta Basin, in which the U&O Reservation is located, have reached unhealthy levels that warrant action. The 2015 8-hour ozone NAAQS is 70 parts per billion (ppb).[55] Compliance with the NAAQS is determined by comparison to a ''design value'' based on a three-year average of the fourth highest daily maximum 8-hour average ozone levels measured in a year at each monitoring site. The state of Utah, the National Park Service (NPS), and the Ute Indian Tribe operate ozone, $PM_{2.5,}$ and NO_2 monitors in and around the Uinta Basin. The ambient air concentrations measured at some of these stations show that ozone levels in the Uinta Basin have repeatedly violated both the 2008 and 2015 ozone NAAQS. Based on 2012–2020 regulatory air quality monitoring data, ozone design values exceed the 2015 ozone NAAQS at five monitoring sites in the Uinta Basin. The highest valid ozone design value in the Uinta Basin for the three-year period from 2017 to 2019 was from the Ouray monitor at 89 ppb.[56] The current (three-year period from 2018 to 2020) highest valid ozone design value in the Uinta Basin is also from the Ouray monitor at 76 ppb. Additionally, higher single 8-hour average ozone concentrations were observed at some monitoring sites, before the sites were designated as regulatory monitors.[57] For example, 8-hour average ozone concentrations reached values as high as 141 ppb at the Ouray monitor in March 2013. This concentration corresponds to an Air Quality Index value of 211, which is characterized as ''Very Unhealthy.''[58]

As discussed previously, the EPA designated areas in the Uinta Basin below 6,250 feet, including portions of the Indian country lands within the U&O Reservation, as marginal nonattainment for the 2015 ozone standard. The fourth maximum ambient air concentration measurement for 2020, the attainment year, is 66 ppb, which is lower than the 2015 ozone NAAQS. Accordingly, Utah and the Ute Indian Tribe requested to extend the August 3, 2021, attainment date for the Uinta Basin Ozone Nonattainment Area by 1-year. On April 13, 2022, the EPA proposed to grant a 1-year attainment date extension for the Uintah Basin Ozone Nonattainment area.[59] The proposal explains that preliminary 2021 ozone monitoring data indicate that the area may not attain the 2015 ozone NAAQS by the proposed extended attainment date of August 3, 2022, but that the area could meet the air quality criteria for a second 1-year extension. As of February 9, 2022, the Uinta Basin area's preliminary 2019–2021 design value was 78 ppb and the preliminary 2021 fourth highest daily maximum 8-hour concentration value was 72 ppb. To qualify for a second 1-year extension, an area's fourth highest daily maximum 8-hour value, averaged over both the original attainment year and the first extension year, must be 70 ppb or less (40 CFR 51.1307(a)(2)). If the preliminary 2021 ozone data are certified, then the fourth highest daily maximum 8-hour value, averaged over 2020 and 2021, would be 69 ppb. [60] The EPA is issuing this notice of final rulemaking (NFRM) because we have concluded that it is necessary and appropriate to take action to protect air quality on the Indian country lands within the U&O Reservation to address these elevated ozone levels.

Ambient ozone is a secondary pollutant formed when the two primary ozone precursors, VOC and NO_X, react in the presence of sunlight. Air quality data and studies in the Uinta Basin show that winter ozone levels above the NAAQS are due to a combination of abundant local ground-level emissions of VOC and NO_X with the unique meteorological and topographic features in the Uinta Basin: strong and persistent temperature inversions forming over snow-covered ground, and elevated terrain completely surrounding a low basin. The stable atmosphere allows the emissions to accumulate and react with sunlight but prevents the emissions from escaping the temperature inversion layer and dispersing. Therefore, ozone continues to form while the unique meteorological conditions persist.[61] The

[53] A source may, however, be subject to certain monitoring, recordkeeping, and reporting (MRR) requirements under the major NSR program, if the change has a reasonable possibility of resulting in a major modification. A source may be subject to both the Federal Indian Country Minor NSR rule and the MRR requirements of the major NSR program.

[54] *See* 40 CFR 49.153, Table 1.

[55] *See* 80 FR 65292 (Oct. 26, 2015).

[56] Valid design values are the regulatory statistic to determine compliance with a NAAQS. They are calculated in accordance with the appropriate NAAQS-specific appendix to 40 CFR part 50. For the 2008 Ozone NAAQS (75 ppb), the appropriate appendix is 40 CFR part 50, appendix P, and for the 2015 Ozone NAAQS (70 ppb) it is 40 CFR part 50, appendix U. Regulatory ozone data is available at *https://www.epa.gov/air-trends/ozone-trends,* accessed Mar. 14, 2022.

[57] A ''regulatory'' monitor is a monitor that meets the EPA's air quality monitoring requirements, including requirements for siting, equipment selection, data sampling protocols, and quality assurance, under the EPA's monitoring regulations at 40 CFR part 58.

[58] The Air Quality Index (AQI) is a normalized system to allow the public to compare health risks of different air pollutants on a common scale. The AQI is divided into six levels of health concern: Good, Moderate, Unhealthy for Sensitive Groups, Unhealthy, Very Unhealthy, and Hazardous.

[59] *See* 87 FR 21842 (Apr. 13, 2022), available at *https://www.govinfo.gov/content/pkg/FR-2022-04-13/pdf/2022-07513.pdf,* accessed Apr. 29, 2022. The criteria to qualify for requesting a 1-year extension of the attainment date are: (1) the state has complied with all requirements and commitments pertaining to the area in the applicable implementation plan; and (2) for a first attainment date extension, an area's fourth highest daily maximum 8-hour value for the attainment year must not exceed the level of the standard.

[60] Preliminary air quality data is available at *https://www.epa.gov/outdoor-air-quality-data/download-daily-data,* accessed Apr. 29, 2022.

[61] The RIA for this final rule contains a more detailed discussion of winter ozone and can be

Continued

state of Utah conducted field studies in the Uinta Basin from 2011 to 2014 to understand the emissions sources and the unique photochemical processes that contribute to winter ozone concentrations within the Uinta Basin. Reports for winter ozone field studies for each year are available on the UDEQ website.[62] These studies found that the oil and natural gas production industry is the most significant anthropogenic contributor of VOC and NO_X emissions in the Basin and primarily responsible for winter ozone formation. The studies also concluded that winter ozone production in the Basin is sensitive to changes in VOC emissions, and that there is greater uncertainty about its sensitivity to changes in NO_X emissions.

The EPA has determined that this final action will result in large reductions of VOC emissions, and that this result is expected to reduce ambient ozone and reduce the severity of exceedances of the 2008 and 2015 ozone NAAQS.[63] As discussed in more detail later, the final action includes a requirement for owners/operators to submit emissions inventories on a triennial basis. This information will enable the successful partnership to continue among the EPA, the UDEQ, the Tribe and industry in maintaining an accurate oil and natural gas emissions inventory for the Uinta Basin to be used, in part, as a tool for managing the Basin's air quality.

We had previously informed the public of our intent to undertake action specific to the Indian country lands within the U&O Reservation; as noted earlier, in the preamble to the National O&NG FIP, we stated: ''For the Uintah and Ouray Reservation, we have sufficient concerns about the air quality impacts from existing sources that we plan to propose a separate U&O FIP.'' [64] After further review, and considering the emissions information presented below, the EPA concludes that those concerns are still warranted, and that this action is necessary and appropriate to address poor air quality on the Indian country lands within the U&O Reservation.

E. Emissions Information

In 2020, the EPA, in cooperation with the UDEQ and the Ute Indian Tribe, developed the UBEI2017-Update, an emission inventory of oil and natural gas activity in the Uinta Basin that was populated with data provided by oil and natural gas operators in the Basin.[65] We are also aware of several other available sources of information on air emissions from oil and natural gas activity in the Uinta Basin, including: (1) the 2017 National Emissions Inventory (2017 NEI); [66] (2) a study by the Western Regional Air Partnership (WRAP); [67] (3) existing true minor source registration data and new and modified true minor source registration submitted to the EPA under the Federal Indian Country Minor NSR Program; [68] and (4) EPA Greenhouse Gas Reporting Program, subpart W Petroleum and Natural Gas Systems.[69] They are discussed in more detail in the Regulatory Impact Analysis (RIA) for this final rule.[70]

The 2017 NEI provides a general picture of the relative contributions of ozone-forming emissions from the oil and natural gas sector as compared to other industry sectors, estimating that emissions from the production segment of the oil and natural gas sector were the largest anthropogenic [71] contributor of both VOC and NO_X emissions in the Uinta Basin, at 97 percent of the VOC emissions and 64 percent of the NO_X emissions. The WRAP study provides a general picture of the relative emissions contribution in the Basin from various oil and natural gas equipment and activities on Indian country lands. The existing minor source registration data provide a general picture of the large percentage of unpermitted and likely uncontrolled minor emissions sources on Indian country lands within the U&O Reservation. EPA Greenhouse Gas Reporting Program, subpart W, provides annual reports by operators of activity levels and methane emissions from oil and natural gas operations in the Uinta Basin. The UBEI2017-Update is a comprehensive source of oil and natural gas source VOC emissions data for the Uinta Basin that provided information for the cost and benefit analysis supporting this rulemaking.

The UBEI2017-Update indicates that the majority of existing oil and natural gas sources in the region are on Indian country lands within the U&O Reservation. As explained in more detail below, most of these are minor sources and are uncontrolled. The 2017 NEI indicates that, compared to other industry sector sources, existing oil and natural gas sources are cumulatively the largest anthropogenic contributor of VOC (97 percent) and NO_X (64 percent) to measured exceedances of the ozone NAAQS in the Uinta Basin. Existing oil and natural gas sources on the portions of the Basin regulated by the UDEQ are subject to emission reduction requirements, while existing sources on Indian country lands within the U&O Reservation were previously either subject to less stringent regulation or no regulation at all.

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viewed in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

[62] ''Uinta Basin Ozone Studies (UBOS),'' *https://deq.utah.gov/air-quality/uinta-basin-ozone-studies-ubos,* accessed Mar. 11, 2022.

[63] As discussed in the RIA for this final rule (available at *https://www.regulations.gov,* Docket ID #EPA–R08–OAR–2015–0709), adoption of the VOC control measures required under this FIP may result in very small NO_X emission increases. We estimate that these additional NO_X emissions would be at most 27 tpy total. Considering the large amount of VOC emission reductions that the same controls will achieve, the small potential NO_X emissions increase will not counteract the effect of the VOC reductions or adversely affect the area's ability to attain the NAAQS.

[64] *See* 81 FR at 35963 (June 3, 2016).

[65] The inventory and supporting analysis can be viewed in the docket for this rule, in the Microsoft Excel spreadsheet titled, ''UO FIP cost and emissions analysis.xlsx'' (Docket ID No. EPA–R08–OAR–2015–0709). This U&O FIP requires owners and operators to submit triennial emissions inventories, similar to a requirement finalized by the UDEQ in March of 2018. These triennial updates will provide information on how emissions are changing in the Basin from the 2017 baseline. *See* Section V (Summary of FIP Provisions).

[66] *See* 2017 National Emissions Inventory (2017 NEI), available at *https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data,* accessed Sept. 28, 2020. Queried: Duchesne & Uintah Counties VOC–NOx all sectors; Ute Indian Tribe of the Uintah & Ouray Indian Reservation VOC–NOx all sectors. EPA's analysis of the 2017 NEI data is available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709), Microsoft Excel spreadsheet titled ''2017 NEI Uinta Basin_Duchesne Counties_U&O_VOC-NOx.xlsx. The UDEQ submitted the UBEI2017 to the 2017 NEI, but later updated it for storage vessel, pneumatic controller, pneumatic pump, fugitive, gas well liquid unloading, blowdowns and pigging and oilfield wastewater emissions that are planned to be submitted to the NEI at a future date (see footnote 75). Analysis of the 2017 NEI for the purposes of this final U&O FIP was prepared using the version publicly available before incorporating these updates from the UDEQ.

[67] Western Regional Air Partnership (WRAP), O&G Emissions Workgroup: Phase III Inventory, Uinta Basin Reports, 2012 Mid-Term Projection Technical Memo, ''Development of 2012 Oil and Gas Emissions Projections for the Uinta Basin'', March 25, 2009, available at *http://www.wrapair2.org/PhaseIII.aspx,* accessed Mar. 14, 2022. Some of the 2014 Uinta Basin Emissions Inventory was generated from prorating the 2012 WRAP estimates (which prorated and adjusted their 2006 work) to 2014 activity levels.

[68] Data from existing true minor source registration reports and data from new and modified true minor oil and natural gas source registrations under the National O&NG FIP, submitted under 40 CFR 49.160 of the Federal Indian Country Minor NSR Program by operators of sources on the Indian country lands within the U&O Reservation.

[69] EPA Greenhouse Gas Reporting Program (GHGRP) Petroleum and Natural Gas Systems, available at *https://www.epa.gov/ghgreporting/ghgrp-petroleum-and-natural-gas-systems,* accessed Mar. 14, 2022.

[70] The RIA can be viewed in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

[71] The calculation excludes biogenic sources of VOC and NO_X, because elevated ozone occurs during the winter when vegetation and soils are presumed to not be a contributor because they are dormant or covered by snow.

Specifically, the UBEI2017-Update shows that 76 percent of all existing oil and natural gas facilities (including well sites processing fluids from multiple individual wells, as well as compressor stations and other processing facilities) in the Uinta Basin are located on Indian country lands within the U&O Reservation. According to the inventory, almost 73,000 tons of VOC and over 6,700 tons of NO_X emissions were emitted in 2017 from existing oil and natural gas sources on Indian country lands within the U&O Reservation. That is approximately 89 percent of the total oil and natural gas-related VOC emissions in the Uinta Basin and approximately 63 percent of the total oil and natural gas-related NO_X emissions in the Uinta Basin. These data confirm that the bulk of the ozone-related emissions in the Uinta Basin are released from sources on the Indian country lands within the U&O Reservation.

Many of the oil and natural gas sources on Indian country lands within the U&O Reservation are uncontrolled. According to the UEBI2017-Update, on the Indian country lands within the U&O Reservation, 85 percent of the total number of existing storage vessels, 98 percent of the total number of existing glycol dehydrators and 99 percent of existing pneumatic pumps are uncontrolled emitters of VOC. By contrast, in areas of the Basin where the EPA has approved the UDEQ to implement the CAA, 68 percent of the total number of existing storage vessels and 52 percent of the total number of existing glycol dehydrators are uncontrolled (uncontrolled pneumatic pump numbers are relatively equivalent to Indian country at 99 percent). The UDEQ has adopted revisions to existing oil and natural gas source requirements and existing minor source permitting requirements, and has adopted new requirements, including a Permit by Rule that replaces the requirement for minor oil and natural gas sources to obtain a site-specific permit.[72] Now that the revised and new requirements are effective, we expect the percentage of uncontrolled existing storage vessels and glycol dehydrators in areas of the Basin where the EPA has approved the UDEQ to implement the CAA will decrease from what was reported in the UBEI2017-Update. The UDEQ's rule revisions and new rules are discussed in more detail in the preamble to the proposed FIP.[73] In addition, the UBEI2017-Update shows that emissions from oil and natural gas wastewater disposal facilities on the Indian country lands within the U&O Reservation comprise approximately 35 percent of the total VOC emissions from oil and natural gas activity on the Indian country lands within the U&O Reservation. As explained in the preamble to the proposed FIP,[74] these facilities may not be controlled under the CAA, because they do not meet the applicability criteria of preconstruction permitting programs or federal emissions standards regulating them.

Based on this collection of emissions information (and other information about meteorological conditions and local geography), the EPA has concluded that winter ozone levels in the Uinta Basin are most significantly influenced by VOC emissions from the presence of numerous minor, unpermitted and largely uncontrolled oil and natural gas production operations on Indian country lands within the U&O Reservation.

F. What is a FIP?

Under section 302(y) of the CAA, the term ''Federal implementation plan'' means ''a plan (or portion thereof) promulgated by the Administrator to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy in a state implementation plan, and which includes enforceable emission limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions of emissions allowances), and provides for attainment of the relevant national ambient air quality standard.'' As discussed previously in section III.B., CAA sections 301(a) and 301(d)(4) and 40 CFR 49.11(a) authorize the EPA to promulgate such FIPs as are necessary or appropriate to protect air quality if a Tribe does not submit or receive EPA approval of a TIP.

The Federal Indian Country Minor NSR rule is an example of a FIP, as discussed in section III.C. Another example of the EPA's use of its FIP authority to protect air quality in areas of Indian country with no EPA-approved program, while at the same time seeking to provide a consistent regulatory environment where appropriate, is the ''FIP for Oil and Natural Gas Well Production Facilities; Fort Berthold Indian Reservation (FBIR; Mandan, Hidatsa, and Arikara Nation), North Dakota.'' [75] In that rule, we took an important initial step to control VOC emissions from existing, new, and modified oil and natural gas operations on the FBIR. We drafted requirements that were consistent to the greatest extent practicable with the most relevant aspects of neighboring state and local rules concerning the air pollutant emitting activities on the FBIR. We did not intend at the time, nor did we expect, the regulation to impose significantly different regulatory burdens upon industry or the residents of the FBIR than those imposed by the rules of state and local air agencies in the surrounding areas.

This U&O FIP specific to Indian country lands within the U&O Reservation will reduce VOC emissions related to the formation of ozone. Exceedances of both the 2008 and the 2015 ozone NAAQS have occurred at air quality monitors on and around the Reservation, and portions of the Uinta Basin, including portions of the U&O Reservation, were designated by the EPA in 2018 as nonattainment for the 2015 ozone NAAQS. There are no currently approved TIPs that apply to existing oil and natural gas sources on Indian country lands within the U&O Reservation. Finally, the majority of the sources covered by this U&O FIP have not previously been subject to federally required emissions controls, as discussed further in Section IV.A of the preamble to the proposed FIP.[76] For all of these reasons, we have concluded that is both necessary and appropriate to protect air quality on the Indian country lands within the U&O Reservation by promulgating this FIP.

G. Oil and Natural Gas Industry in the Uinta Basin

The oil and natural gas industry in the Uinta Basin includes the extraction and production of oil and natural gas, as well as the processing, transmission, and distribution of natural gas. Specifically, for oil, the industry in the Uinta Basin includes all operations from the well to transfer to an oil transmission pipeline or other means of transportation to a petroleum refinery. The petroleum refinery is not considered part of the oil and natural gas industry. Thus, with respect to

[72] Utah State Bulletin, Official Notices of Utah State Government, Filed Jan. 3, 2018, 12:00 a.m. through Jan. 16, 2018, 11:59 p.m., 11:59 p.m., Number 2018–3, February 01, 2018, Nancy L. Lancaster, Managing Editor, pages 46–68, available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709.

[73] *See* 85 FR 3504–3506, Section IV. D. Developing the Proposed Control Requirements, 3. Evaluation of State Oil and Natural Gas and Permitting-Related Requirements.

[74] *See* 85 FR 3503–3504, Section IV. D. Developing the Proposed Control Requirements, 2. Evaluation of Federal Oil and Natural Gas and Permitting-Related Requirements.

[75] *See* 78 FR 17836 (Mar. 22, 2013).

[76] *See* 85 FR 3501, Section IV. Developing the Proposed Control Rule, A. Rationale for the Proposed Rule.

crude oil, the oil and natural gas industry ends where crude oil enters an oil transmission pipeline or other means of transportation to a petroleum refinery. For natural gas, the industry includes all operations from the well to the final end user.

The oil and natural gas industry in the Uinta Basin can generally be separated into four segments: (1) oil and natural gas production; (2) natural gas processing; (3) natural gas transmission and storage; and (4) natural gas distribution. This U&O FIP for oil and natural gas sources on Indian country lands within the U&O Reservation focuses on existing, new, and modified sources in the first and second segments, oil and natural gas production and natural gas processing, because the existing minor sources in those segments cumulatively contribute the largest portion of VOC emissions from the oil and natural gas industry on the Indian country portion of the U&O Reservation. There are more than 6,870 individual oil and natural gas sources (operated by 33 distinct entities) on the Indian country lands within the U&O Reservation, the majority of which are well sites in the oil and natural gas production segment.[77] As discussed earlier, the 2017 NEI shows that emissions from the production segment of the oil and natural gas sector were estimated to be the largest anthropogenic contributor of both VOC and NO_X emissions in the Uinta Basin. Comparatively, the categories that include oil and natural gas storage and transfer and bulk gasoline terminals (segments 3 and 4), are reported in the 2017 NEI as contributing less than one percent each of the total VOC and NO_X emissions in the Uinta Basin.[78] Of the 13,363 individual active oil and natural gas wells in the Uinta Basin, over 10,108 wells, or about 76 percent, are on Indian country lands within the U&O Reservation.

The oil and natural gas production segment in the Uinta Basin includes wells and all related processes used in the extraction, production, recovery, lifting, stabilization, and separation or treatment of oil and/or natural gas (including condensate). Production components in the Uinta Basin may include wells and related casing head, tubing head, and ''Christmas tree'' piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices, pneumatic pumps, and natural gas dehydrators. Production operations in the Uinta Basin also include the well drilling, completion, and workover processes, and include all the portable non-self-propelled apparatuses associated with those operations. Production sites in the Uinta Basin include not only the sites where the wells themselves are located, but also centralized gas and liquid gathering sources where oil, condensate, produced water, and natural gas from several wells may be separated, stored, and treated. Production components in the Uinta Basin also include the smaller diameter, low-to-medium-pressure gathering pipelines and related components that collect and transport the oil, natural gas, and other materials and wastes from the wells or well pads.

The natural gas production segment in the Uinta Basin ends where the natural gas enters a natural gas processing plant. Where there is no processing plant, the natural gas production segment ends at the point where the natural gas enters the transmission segment for long-line transport. The crude oil production segment in the Uinta Basin ends at the storage and load-out terminal, which is the point of custody transfer to an oil pipeline or for transport of the crude oil to a petroleum refinery via trucks or railcars.

Each producing crude oil and natural gas field has its own unique properties. The composition of the crude oil and the natural gas as well as the reservoir characteristics are likely to be different across all reservoirs. The RIA for this rule provides a more detailed overview of the products and components of the oil and natural gas industry that are relevant to the activities in the Uinta Basin.[79]

IV. Summary of the Final U&O FIP

A. Overview

The emissions control and other requirements of this final FIP that will reduce VOC emissions from existing, new, and modified oil and natural gas sources on Indian country lands within the U&O Reservation are summarized in this section. Significant changes since proposal are discussed in more detail in section V of this preamble. The FIP includes emissions control efficiency requirements and operational and work practice standards, each with associated monitoring, testing, recordkeeping, and reporting requirements, as appropriate. Oil and natural gas sources must comply with these requirements, except as specifically exempted under the FIP for certain equipment or activities otherwise subject to existing federal standards 40 CFR part 60, subparts OOOO or OOOOa, or 40 CFR part 63, subpart HH. Also discussed in this section are the features of the FIP that are necessary to facilitate its implementation.

This final rule applies to owners or operators of oil and natural gas sources that either produce oil and natural gas or process natural gas, that are located on Indian country lands within the U&O Reservation, and that meet the applicability criteria specified for each set of requirements. It includes the following provisions in 40 CFR part 49:

49.4169 Introduction.
49.4170 Delegation of authority of administration to the Tribe.
49.4171 General provisions.
49.4172 Emissions Inventory.
49.4173 VOC emissions control requirements for storage vessels.
49.4174 VOC emissions control requirements for dehydrators.
49.4175 VOC emissions control requirements for pneumatic pumps.
49.4176 VOC emissions control requirements for covers and closed-vent systems.
49.4177 VOC emissions control devices.
49.4178 VOC emissions control requirements for fugitive emissions.
49.4179 VOC emissions control requirements for tank truck loading.
49.4180 VOC emissions control requirements for pneumatic controllers.
49.4181 Other combustion devices.
49.4182 Monitoring and testing requirements.
49.4183 Recordkeeping requirements.
49.4184 Notification and reporting requirements.

We do not expect a substantial number of the existing oil and natural gas sources subject to this U&O FIP to also be subject to NSPS OOOO or OOOOa, or NESHAP HH, for the specific equipment and activities regulated. However, to minimize regulatory burdens where such a potential overlap does exist, this rule finalizes the proposed provisions that equipment or activities that are affected

[77] *2017 Uinta Basin Oil and Natural Gas Emissions Inventory Update* (UBEI2017-Update). The inventory and supporting analysis can be viewed in the docket for this rulemaking. *See* ''UO FIP cost and emissions analysis.xlsx'' (Docket ID No. EPA–R08–OAR–2015–0709).

[78] Based on the NEI Source Type to Sector Crosswalk in the 2017 NEI, available at *https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data,* accessed Mar. 14, 2022. Queried: Duchesne & Uintah Counties VOC–NOx all sectors; Ute Indian Tribe of the Uintah & Ouray Indian Reservation VOC–NOx all sectors. The EPA's analysis of the 2017 NEI data is available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709), Microsoft Excel spreadsheet titled ''2017 NEI Uinta Basin_Dechesne Counties_U&O_VOC-NOx.xlsx.''

[79] The RIA for the final rule can be viewed in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

by any requirement in this U&O FIP and that are also subject to the substantive emissions control requirements in those EPA standards will not be subject to this FIP's substantive emissions control requirements for such equipment and activities. As an example, given the exemptions being finalized, if an existing, new, or modified oil and natural gas source on Indian country lands within the U&O Reservation has storage vessels, pneumatic pumps, and fugitive emissions components that are subject to the emissions control requirements of NSPS OOOOa, then that source would be subject to the substantive emissions control requirements for glycol dehydrators in the FIP, but not to the FIP's substantive emissions control requirements for storage vessels, pneumatic pumps, or fugitive emissions components.

B. Introduction

In 40 CFR 49.4169 (Introduction) we are finalizing our proposal to specify: (1) the purpose of this U&O FIP; (2) the general applicability of this U&O FIP; and (3) the compliance schedule for this U&O FIP.

We are finalizing text that: (1) establishes provisions for delegation of authority to allow the Ute Indian Tribe to assist the EPA with administration of this U&O FIP in 40 CFR 49.4170; (2) establishes general provisions and definitions applicable to oil and natural gas sources in 40 CFR 49.4171; (3) establishes a requirement for oil and natural gas sources to submit emissions inventories on a triennial basis, beginning with an inventory for calendar year 2023 in 40 CFR 49.4172; and (4) establishes, in 40 CFR 49.4173 through 49.4184, enforceable requirements to control and reduce VOC emissions from oil and natural gas well production and storage operations, natural gas processing, and gathering and boosting operations at oil and natural gas sources on Indian country lands within the U&O Reservation.

This final rule provides that compliance with the rule for oil and natural gas sources that commence construction on or after the effective date of the final rule is required upon startup. Compliance for sources existing as of the effective date of the final rule is required no later than 12 months after the effective date of the final rule. We concluded that it is important to allow owners/operators of existing sources a reasonable period of time to conduct any necessary retrofit-related activities, such as (1) acquiring control devices, (2) conducting manufacturer-recommended testing to be compliant with the requirements, and (3) securing the necessary trained personnel to install compliant devices and associated piping and instrumentation. We expect that there will be about 2,165 existing oil and natural gas sources that may require equipment retrofit and installation of VOC emission control equipment (combustion controls) under the final rule. Additionally, we estimate that more than 700 high-bleed pneumatic controllers will need to be retrofitted to low-or no-bleed. We have determined that providing 12 months from the effective date of the final rule to install retrofits at existing sources is a reasonable amount of time for efficient, cost-effective project planning that accounts for a level, sustained equipment and labor resource demand that can be supported by the vendor community, while ensuring that meaningful emissions reductions will be achieved that provide near-term benefits to improve air quality and make progress toward future attainment.[80]

We are also finalizing a provision to allow an owner or operator on a case-specific basis to submit a written request to the EPA for an extension of the compliance deadline for existing sources, which must include appropriate justification of the reason for the request. Any approval or denial of an extension request, including the length of any approved extension, will be based on the merits of each case. Factors that the EPA will consider in deciding whether to grant an extension request under the provision include the economic and technical feasibility of meeting this U&O FIP's control requirements in the prescribed timeframe. The final FIP specifies the criteria that the EPA will apply in responding to requests for extension of the compliance period, including that the request must be submitted before the compliance deadline, must identify the specific provisions for which an extension is being requested and include an alternative compliance deadline, and must provide a rationale for the request with supporting information explaining how the operator will effectively meet all applicable requirements after the requested alternative compliance deadline.

[80] 12 months is a tighter compliance timeframe than is required for existing sources in NESHAP regulations, which is typically 3 years. The purpose of this proposed U&O FIP, though, is to address air quality in a timely fashion. Moreover, the final rule allows sources to request extensions of the compliance date beyond the 12 months if needed.

C. Provisions for Delegation of Administration to the Ute Indian Tribe

We are establishing in 40 CFR 49.4170 (Delegation of authority of administration to the Tribe) the steps by which the Ute Indian Tribe may request delegation to assist us with the administration of this rule, and the process by which the Regional Administrator of EPA Region 8 may delegate to the Ute Indian Tribe the authority to assist with such administration. As described in the regulatory provisions, any such delegation will be accomplished through a delegation of authority agreement between the Regional Administrator and the Tribe. This section provides for administrative delegation of this federal rule and does not affect the TAS eligibility criteria under CAA section 301(d) and 40 CFR 49.6 should the Ute Indian Tribe decide to seek such treatment for the purpose of administering its own EPA-approved TIP under tribal law. Administrative delegation is a separate process from TAS under the TAR. Under the TAR, Indian tribes seek the EPA's approval of their eligibility to implement CAA programs under their own laws. The Ute Indian Tribe will not need to seek TAS under the TAR for purposes of requesting to assist us with administration of this rule through a delegation of authority agreement. If delegation does occur, the rule would continue to operate under federal authority on Indian country lands within the U&O Reservation, and the Ute Indian Tribe would assist us with administration of the rule to the extent specified in the agreement.

D. General Provisions

We are finalizing in 40 CFR 49.4171 (General provisions): (1) a requirement to design, operate, and maintain all equipment used for hydrocarbon liquid and gas collection, storage, processing, and handling operations covered under this rule, in a manner consistent with good air pollution control practices and that minimizes leakage of VOC emissions to the atmosphere. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA, including monitoring results, review of operating and maintenance procedures, and inspection of the source; and (2) definitions.

E. Emissions Inventory Requirements

We are finalizing in 40 CFR 49.4172 a requirement for owners/operators of oil and natural gas sources with the potential to emit one or more NSR-regulated pollutants at levels greater than one tpy to submit an annual emissions inventory, once every three years beginning with calendar year 2024, that covers emissions from the previous calendar year (2023 for the first required inventory). Each triennial inventory must be submitted no later than April 15th of the year after each inventory year. The triennial emissions inventory requirement will suffice for the purpose of continued updates to the comprehensive Uinta Basin oil and natural gas emissions inventory by the UDEQ, the Ute Indian Tribe, and the EPA. Owners/operators must submit actual emissions for each emissions unit at each oil and natural gas source covered by the requirement in a standard format specified by the Regional Office and available on our website. The format will be consistent with the format used by the UDEQ to collect information from sources in the Uinta Basin outside of Indian country lands within the U&O Reservation.

F. VOC Emissions Control Requirements

The discussion in this section details the final VOC emissions control requirements of this FIP and how they compare to existing state and federal requirements for the equipment and activities listed in Table 3. The most notable difference between the final VOC emissions control requirements of this FIP and the Utah Oil and Gas Rules [81] and Utah Permit Requirements [82] is that the Utah permit by rule's 4 tpy total VOC emissions threshold for requiring controls does not include pneumatic pump emissions. We have determined that emissions from pneumatic pumps are a large source of VOC emissions on the Indian country lands within the U&O Reservation, but a negligible source of VOC emissions in the areas in the Basin where the EPA has approved the UDEQ to implement the CAA. This difference in the share of pneumatic pumps emissions in the inventory is because the majority of natural gas production operations, which use gas-driven pneumatic pumps, occurs on the Reservation, while lands where air quality is managed by the UDEQ feature mostly oil production. This difference is explained in more detail later in this section.

TABLE 3—U&O FIP VOC EMISSIONS CONTROL REQUIREMENTS FOR EXISTING, NEW, AND MODIFIED OIL AND NATURAL GAS SOURCES VERSUS UDEQ AND OTHER FEDERAL [83] CONTROL REQUIREMENTS

U&O FIP VOC Emissions Controls			Utah oil and gas rules and Utah permit requirements	NSPS OOOO	NSPS OOOOa	NESHAP HH
Final FIP requirements (section in 40 CFR part 49)	Applicability threshold	Control efficiency (percent)				
Storage vessel VOC emission control requirements (§ 49.4173).	Source-wide potential for VOC emissions from the collection of all storage vessels, dehydrators and pneumatic pumps ≥4 tpy.	Reduce VOC by 95.0 percent or route to a process. See also VOC emission control devices later in this table (§ 49.4177).	Issued Utah Permit Requirements (BACT for site-specific & general approval orders)—Reduce VOC by 98 percent or route to a process where source-wide uncontrolled actual VOC emissions from the collection of all storage vessels, dehydrators and pneumatic pumps ≥4 tpy. Utah Oil and Gas Rules—Reduce VOC by 95 percent or route to a process if total uncontrolled actual emissions from the collection of dehydrators and storage vessels ≥4 tpy VOC (does not include pneumatic pump emissions), or if source with storage vessels only has through put ≥8,000 bbl crude oil or 2,000 bbl condensate, on rolling 12-month basis—unless ≤4 tpy source-wide uncontrolled actual emissions of VOC from the collection of all storage vessels.	Reduce VOC by 95.0 percent or route to a process for individual storage vessels with potential for ≥6 tpy per storage vessel constructed, reconstructed or modified after August 23, 2011, and on or before September 18, 2015 (alternatively, no control required if uncontrolled actual VOC emissions maintained <4 tpy).	Reduce VOC by 95.0 percent or route to a process for individual storage vessels with potential for ≥6 tpy per storage vessel constructed, reconstructed or modified after September 18, 2015 (alternatively, no control required if uncontrolled actual VOC emissions maintained <4tpy).	Reduce HAP by 95.0 percent or route to a process for individual storage vessels with potential for flash emissions and actual annual average hydrocarbon liquid throughput ≥79,500 liters/day.

[81] Utah Administrative Code Chapter R307–500 Series (Oil and Gas), available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709). These rules, referred to collectively as the ''Utah permit by rule,'' are state-only rules and the UDEQ has not submitted them to the EPA for approval in the Utah SIP.

[82] Utah Administrative Code Chapter R307–401 (Permits: New and Modified Sources), available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709); See 40 CFR part 52, subpart TT.

[83] The National O&NG FIP incorporates the requirements of the eight standards, as they apply to a source. To make emissions control requirements across the Basin consistent, this U&O FIP goes beyond the eight federal standards to regulate certain equipment and activities that are not regulated by established EPA standards (or are regulated differently) but are regulated in UDEQ standards. In addition, the EPA issued subsequent rules that revised certain provisions of NSPS OOOO and OOOOa (The 2020 Policy Rule and 2020 Technical Rule; see discussion above in Section I.B.). The 2021 CRA resolution disapproved the policy amendments of NSPS OOOO and OOOOa. PL 17–23 (June 30, 2021). The requirements summarized in this table reflect the standards that are in effect today—the methane standards in the 2016 NSPS OOOOa and the 2016 VOC standards in NSPS OOOO and OOOOa, as they were amended in 2020. The EPA's Oil and Natural Gas Sector Climate Review Proposed Rule would revise existing VOC standards under NSPS OOOO and OOOOa, establish new methane and VOC standards for new and modified emissions sources not previously covered by NSPS OOOO and OOOOa, and establish emissions guidelines for existing sources. This table does not reflect those proposed standards and guidelines. We may revisit this final action in the future based on any final action we take under CAA section 111 with the Oil and Natural Gas Sector Climate Review rulemaking.

TABLE 3—U&O FIP VOC EMISSIONS CONTROL REQUIREMENTS FOR EXISTING, NEW, AND MODIFIED OIL AND NATURAL GAS SOURCES VERSUS UDEQ AND OTHER FEDERAL [83] CONTROL REQUIREMENTS—Continued

U&O FIP VOC Emissions Controls			Utah oil and gas rules and Utah permit requirements	NSPS OOOO	NSPS OOOOa	NESHAP HH
Final FIP requirements (section in 40 CFR part 49)	Applicability threshold	Control efficiency (percent)				
Dehydrators VOC emission control requirements (§ 49.4174).		See VOC emission control devices later in this table (§ 49.4177).	Issued Utah Permit Requirements (BACT for site-specific & general approval orders)—Reduce VOC by 98 percent or route to a process where source-wide uncontrolled actual VOC emissions from the collection of all storage vessels, dehydrators and pneumatic pumps ≥4 tpy. Utah Oil and Gas Rules—Reduce VOC by 95 percent if total uncontrolled actual emissions from the collection of dehydrators and storage vessels ≥4 tpy VOC (does not include pneumatic pump emissions).	Not covered	Not covered	For units at major HAP sources and non-urban area sources with actual annual average flowrate of natural gas ≥85,000 standard m3/day, reduce HAP by 95.0 percent or route to a process. Units with actual annual average flowrate of natural gas <85,000 standard m3/day not covered—this is the majority of units on Indian country lands within the U&O Reservation.
Pneumatic pumps VOC emission control requirements (§ 49.4175).		See VOC emission control devices later in this table (§ 49.4177).	Issued Utah Permit Requirements (BACT for site-specific & general approval orders)—Reduce VOC by 98 percent or route to a process where source-wide uncontrolled actual VOC emissions from the collection of storage vessels, dehydrators and pneumatic pumps ≥4 tpy. Utah Oil and Gas Rules does not require control of pneumatic pump emissions.	Not covered	Reduce VOC by 95.0 percent (if control device is already on site) or route to a process (if technically feasible) for natural gas-driven diaphragm pneumatic pumps at well sites constructed, reconstructed or modified after September 18, 2015. Zero natural gas emissions for natural gas processing plants constructed after September 18, 2015.	Not covered.
Covers and closed-vent system VOC emission control requirements (§ 49.4176).	Source-wide potential for VOC emissions from the collection of all storage vessels, dehydrators and pneumatic pumps ≥4 tpy.	100 percent of VOC emissions routed to process or control device.	100 percent of storage vessel, dehydrator and pneumatic pump emissions routed to control device or process in issued Utah Permit Requirements and Rules (BACT for site-specific & general approval orders). Utah Oil and Gas Rules—100 percent storage vessel and dehydrator emissions routed to control device or process (Utah Oil and Gas Rules do not include routing pneumatic pump emissions).	100 percent of storage vessel VOC emissions routed to control device or process.	100 percent of storage vessel emissions routed to control device or process.	100 percent of HAP emissions, if required to control glycol dehydrators and/or storage vessels.
VOC emission control devices (§ 49.4177).	Source-wide potential for VOC emissions from the collection of all storage vessels, dehydrators and pneumatic pumps ≥4 tpy.	95.0 percent continuously.	98.0 percent continuous VOC control efficiency for Issued Utah Permit Requirements (BACT for site-specific & general approval orders). 95 percent continuous control efficiency for Utah Oil and Gas Rules.	95.0 percent continuous VOC control efficiency.	95.0 percent continuous VOC control efficiency.	If required to control glycol dehydrator or storage vessel HAP emissions, must reduce HAP by 95.0 percent, or maintain <20 parts per million volume (ppmv) or 1 tpy benzene.

TABLE 3—U&O FIP VOC EMISSIONS CONTROL REQUIREMENTS FOR EXISTING, NEW, AND MODIFIED OIL AND NATURAL GAS SOURCES VERSUS UDEQ AND OTHER FEDERAL [83] CONTROL REQUIREMENTS—Continued

U&O FIP VOC Emissions Controls			Utah oil and gas rules and Utah permit requirements	NSPS OOOO	NSPS OOOOa	NESHAP HH
Final FIP requirements (section in 40 CFR part 49)	Applicability threshold	Control efficiency (percent)				
Fugitive emissions VOC emission control requirements (§ 49.4178).	Source-wide potential for VOC emissions from the collection of all storage vessels, dehydrators and pneumatic pumps ≥4 tpy. Or Well site production >15 boe per day (rolling consecutive 12-month average).	NA–Semi-annual surveys	Utah Oil and Gas Rules—semi-annual surveys at all registered well sites required to control storage vessel and/or dehydrator VOC emissions. Issued Utah Permit Requirements (sources exempt from Utah Oil and Gas Rules) require LDAR, ranging from annual to quarterly for all approved (*i.e.,* permitted) oil and natural gas sources, including compressor stations.	For natural gas processing plants constructed, reconstructed, or modified after August 23, 2011, and on or before September 18, 2015—LDAR requirements as referenced in NSPS VVa, with periodic EPA Method 21 surveys on specific equipment types.	For well sites and compressor stations constructed, reconstructed or modified after September 18, 2015—Fugitive emissions surveys using OGI conducted semiannually (well sites) and quarterly (compressor stations). For natural gas processing plants constructed, reconstructed or modified after September 18, 2015—LDAR requirements as referenced in NSPS VVa, with periodic EPA Method 21 surveys on specific equipment types.	Ensure closed-vent system operates with no detectable emissions if required to control glycol dehydrator or storage vessel HAP emissions.
Tank truck loading VOC emission control requirements (§ 49.4179).	None—applies to all existing sources.	NA—Bottom filling or submerged fill pipe.	Utah Oil and Gas Rules—more stringent, as capture and control of VOC emissions (95 percent efficiency) required at registered sources required to control storage vessel and glycol dehydrator emissions.	Not covered	Not covered	Not covered.
Pneumatic controllers VOC emission control requirements (§ 49.4180).		NA—meet the standards of NSPS OOOO or OOOOa.	Utah Oil and Gas Rules—Meet standards of NSPS OOOO.	For continuous bleed natural gas driven pneumatic controllers constructed, reconstructed or modified after October 15, 2013 and on or before September 18, 2015, zero-bleed for processing plants and low-bleed (<6 scfh) elsewhere.	For continuous bleed natural gas driven pneumatic controllers constructed, reconstructed or modified after September 18, 2015, zero-bleed for processing plants and low-bleed (<6 scfh) elsewhere.	Not covered.
Other combustion devices (§ 49.4181).		NA—must be equipped with automatic ignition device.	Utah Oil and Gas Rules—must be equipped with automatic ignition device.	Not covered	Not covered	Not covered.

1. Storage Vessels, Glycol Dehydrators, and Pneumatic Pumps

For existing, new, and modified sources, we are finalizing in 40 CFR 49.4173 (Storage vessel VOC emission control requirements), 40 CFR 49.4174 (Dehydrators VOC emission control requirements), and 40 CFR 49.4175 (Pneumatic pumps VOC emission control requirements) the requirement that owners and operators of affected storage vessels, glycol dehydrators, and natural gas-driven pneumatic pumps either: (1) reduce VOC emissions from flashing, working, standing, and breathing losses from the collection of all crude oil, condensate, intermediate hydrocarbon and produced water storage vessels, glycol dehydrator process vents (glycol dehydrator regenerator or still vent and the vent from the dehydrator flash tank, if present), and pneumatic pumps, by at least 95.0 percent on a continuous basis; or (2) maintain the source-wide uncontrolled actual VOC emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps at a rate of less than 4 tpy. We are finalizing the requirement that applicability for the VOC emissions control requirements be determined specifically according to the following criteria. For oil and natural gas sources that began operation before the effective date of the final rule, we are requiring that applicability be determined using potential for VOC emissions. Potential for VOC emissions must be calculated using a generally accepted model or calculation methodology based on the maximum average daily throughput, as determined for existing sources using the highest 30-day period of production in the 12 consecutive months before the compliance deadline of the rule for each affected source. The determination may take into account requirements under legally and practicably enforceable limits in an applicable operating permit or other applicable federal requirement, such as those in NSPS OOOO or OOOOa, or NESHAP HH. For oil and natural gas sources that begin operation or modification after the effective date of the final rule, we are requiring that applicability for glycol dehydrators and pneumatic pumps be determined using potential to emit VOC, and that emissions from the collection of all storage vessels be controlled upon startup for a minimum of 12 consecutive months. This requirement for new and modified storage vessels is being finalized because of the uncertainty of well production levels before operation begins. After a minimum of 12 consecutive months of operation, controls may be removed if source-wide uncontrolled actual VOC emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps are demonstrated to be less than 4 tpy.

We are requiring that owners or operators demonstrate that the source-wide uncontrolled actual VOC emissions from the collection of all crude oil, condensate, intermediate hydrocarbon liquids and produced water storage vessels, glycol dehydrator process vents, and pneumatic pumps have been maintained below 4 tpy, using records of monthly determinations of uncontrolled actual VOC emission rates for the 12 consecutive months immediately preceding the demonstration. The uncontrolled actual VOC emissions rate must be calculated using a generally accepted model or calculation methodology.

The final rule requires that the owner or operator re-evaluate the source-wide uncontrolled actual VOC emissions on a monthly basis. If the results of the monthly determination show that the uncontrolled actual VOC emission rate is greater than or equal to 4 tpy, the owner or operator will have 30 days to switch to the first option specified and control VOC emissions by at least 95 percent continuously. We are finalizing an exemption to the VOC emissions control requirements for each emergency storage vessel that meets the following requirements: (1) the storage vessel is not used as an active storage vessel; (2) the owner or operator empties the storage vessel no later than 15 days after receiving fluids; (3) the storage vessel is equipped with a liquid level gauge or equivalent device; and (4) records of the use of each vessel are kept indicating the date the vessel received fluids or was discovered to have received fluids, the date the vessel was emptied and the volume of fluids emptied in barrels.

The final VOC emissions control applicability provisions and other requirements are the same as or comparable on balance with the requirements in the Utah Permit Requirements and/or Utah Oil and Gas Rules. The methods for determining applicability of the control requirements are the same as those in site-specific minor source BACT analyses in the Utah Permit Requirements. In site-specific approval orders that have been issued, the UDEQ requires VOC emissions controls for source-wide emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps at oil and natural gas sources [84] when the source-wide potential for VOC emissions from that equipment is greater than or equal to 4 tpy. We have also determined that controlling emissions above the 4 tpy VOC level is cost-effective and will achieve meaningful emissions reductions on Indian country lands within the U&O Reservation.[85] The methods for determining applicability of the control requirements are comparable on balance with the UDEQ's recently adopted Utah Oil and Gas Rules, except that those rules do not consider emissions from or control of pneumatic pumps.[86] The reason for this difference is discussed later when we describe this FIP's requirements for pneumatic pumps. The Utah Oil and Gas Rules require all new and modified storage vessels (*i.e.,* those that begin operation on or after January 1, 2018) to control emissions upon startup of operation for a minimum of one year. The requirement in this FIP to control emissions from the collection of all new and modified storage vessels for at least 12 consecutive months, the exemption for emergency storage vessels, and the provision allowing removal of controls from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps are also the same as the requirements in the Utah Oil and Gas Rules, with the exception of pneumatic pump emissions and control mentioned earlier, which will be discussed in more detail later.

We are finalizing the option that the owner or operator capture and route all subject emissions through a closed-vent system to an enclosed combustor or flare that is designed and operated to reduce the mass content of VOC in the emissions vented to it by at least 95.0 percent. Requirements for closed-vent systems are established under conditions specified in 40 CFR 49.4176 (VOC emission control requirements for covers and closed-vent systems), and requirements for operation and monitoring of control devices are established under conditions specified in 40 CFR 49.4177 (VOC Emission Control Devices) and 40 CFR 49.4182 (Monitoring Requirements), all of which are discussed in detail below in the summaries of Covers, Closed-Vent Systems, and VOC Emission Control Devices and Monitoring Requirements.

We are finalizing the alternative option that the owner or operator design operations to recover 100 percent of the emissions and recycle them for use in a process unit or incorporate them into a product. These control options are the same as the Utah Permit Requirements and the Utah Oil and Gas Rules.

As described earlier, regulating pneumatic pumps in this U&O FIP is not comparable to the UDEQ's Utah Oil and Gas Rules, because those rules do not include requirements for pneumatic pumps.[87] But the approach in this U&O FIP to controlling pneumatic pumps by routing emissions to the same control device that controls emissions from the collection of all storage vessels and glycol dehydrators is the same as the UDEQ's approach to controlling pneumatic pumps in site-specific approval orders issued under Utah Permit Requirements. We are confident that this approach will help achieve ozone air quality improvements through this U&O FIP, as the UBEI2017-Update shows that VOC emissions from pneumatic pumps constitute 16 percent of the total oil and natural gas-related VOC emissions on Indian country lands within the U&O Reservation.[88]

We do not expect that a substantial number of existing oil and natural gas sources that would meet the applicability criteria of this U&O FIP will also be subject to NSPS OOOO or OOOOa, or NESHAP HH. However, to address any potential regulatory overlap, we are providing that any affected storage vessels, glycol dehydrators, or pneumatic pumps that

[84] The docket for this rulemaking contains several examples of UDEQ site-specific minor source NSR permits (approval orders) for Crude Oil and Natural Gas Well Sites and/or Tank Batteries (DAQE–AN151010001–15, DAQE–AN149250001–14, and DAQE–AN143640003–15). UDEQ site-specific approval order requirements are based on BACT analyses for oil and natural gas sources concluding that combustion of VOC emissions from crude oil and condensate storage tanks, glycol dehydrators, and pneumatic pumps is economically and technically feasible when the source-wide potential for VOC emissions from those emissions sources is equal to or greater than 4 tpy. The analyses rely in part on the EPA's analysis in the April 12, 2013 NSPS OOOO reconsideration, and the finding that emissions from those three emissions sources at a single source can feasibly be routed to the same combustor. Though the 4 tpy threshold is not specifically stated in the approval orders, if a source applying for a site-specific approval order has source-wide storage tank, glycol dehydrator, and pneumatic pump VOC emissions equal to or greater than 4 tpy, the order contains requirements to control those emissions.

[85] The RIA in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709) contains more detailed information on our analyses.

[86] In response to an EPA comment on UDEQ's proposal questioning why issued approval orders and the GAO cover pneumatic pumps, but the new Utah Oil and Gas Rules do not, the UDEQ stated that the 2014 Uinta Basin Emissions Inventory indicated that pneumatic pump emissions constitute an insignificant portion of the total VOC emissions at Utah-regulated sources in the Basin. The comments and UDEQ's responses are available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

[87] We note that the Utah Oil and Gas Rules do not contain requirements for pneumatic pumps. We are finalizing requirements for pneumatic pumps requirements, as we have identified emissions from existing pneumatic pumps as being a significant source of VOC emissions on the Indian country lands within the U&O Reservation.

[88] By contrast, the UBEI2017-Update shows that there are a very low number of pneumatic pumps installed and operating on lands in areas of the Basin where the EPA has approved the UDEQ to implement the CAA; the UDEQ has stated that this fact is the reason the Utah Oil and Gas Rules do not have control requirements for pneumatic pumps (see the response to comments on the UDEQ's proposed rules in the docket for this rulemaking).

are subject to the emissions control requirements in those EPA standards, are not subject to the requirements in this U&O FIP for such equipment and activities, including monitoring, recordkeeping, and reporting requirements associated with such equipment and activities.

2. Covers, Closed-Vent Systems

For affected existing, new, and modified sources that are required to control emissions from the collection of all storage vessels, glycol dehydrators and pneumatic pumps per 40 CFR 49.4173 through 49.4175, we are finalizing in 40 CFR 49.4176 (VOC emission control requirements for covers and closed-vent systems) to require, as applicable, the use of covers on all storage vessels, and the use of closed-vent systems with equipment that captures and routes VOC emissions to the respective vapor recovery or VOC emission control devices. Because closed-vent systems are common to control requirements for storage vessels, glycol dehydrators and pneumatic pumps, we are finalizing these requirements in a separate section to avoid redundancy. Section 49.4176 also specifies construction and operational requirements for the covers and closed-vent systems. The construction and operational requirements for the covers and closed-vent systems are intended to provide legal and practical enforceability to ensure that all captured VOC emissions are routed to the respective vapor recovery or VOC emission control devices. In addition, for affected existing, new, and modified sources that are required to control emissions from the collection of all storage vessels, glycol dehydrators and pneumatic pumps, in 40 CFR 49.4177 (VOC emission control devices) we are finalizing specific legally and practicably enforceable construction and operational requirements for enclosed combustors and flares.

We are finalizing in 40 CFR 49.4176 (VOC emission control requirements for covers and closed-vent systems) the requirement that each owner or operator equip the openings on each affected storage vessel with a cover that ensures that flashing, working, standing and breathing losses are efficiently routed through a closed-vent system to a vapor recovery system, an enclosed combustor, or a flare. We are finalizing the requirement that each cover and all openings on the cover (*e.g.,* access hatches, sampling ports, and gauge wells) form a continuous barrier over the entire surface area of the crude oil, condensate, intermediate hydrocarbon liquids or produced water in the storage vessel. Each cover opening must be secured in a closed, sealed position (*i.e.,* covered by a gasketed lid or cap) whenever material is in the storage vessel on which the cover is installed, except when it is necessary to use an opening to: (1) add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit); (2) inspect or sample the material in the unit; or (3) inspect, maintain, repair, or replace equipment inside the unit.

We are requiring that all vent lines, connections, fittings, valves, relief valves, and any other appurtenance employed to contain and collect emissions and transport them to the vapor recovery or VOC control equipment be maintained and operated properly at all times, and that they be designed to operate with no detectable emissions. If a closed-vent system contains one or more bypass devices that could be used to divert all or a portion of the emissions from entering the vapor recovery or VOC control devices, we are requiring that the owner or operator meet one of the following options for each bypass device: (1) at the inlet to the bypass device, properly install, calibrate, maintain, and operate a flow indicator capable of taking periodic readings and sounding an alarm when the bypass device is open such that the emissions are being, or could be, diverted away from the control device and into the atmosphere; or (2) secure the bypass device valve in the non-diverting position using a car-seal or a lock-and-key type configuration.

The cover and closed-vent system requirements are comparable on balance with UDEQ requirements for storage vessels in both the issued site-specific approval orders and the Utah Oil and Gas Rules. The site-specific approval orders require storage vessel thief hatches to be closed and latched except during storage vessel unloading or other maintenance activities. They also require that thief hatches be inspected once every three months to ensure that thief hatches are closed and latched, and that any associated gaskets are in good working condition. Similarly, the Utah Oil and Gas Rules for storage vessels require thief hatches to be kept closed and latched except during unloading or maintenance. The U&O FIP requirements for covers and closed-vent systems were developed by consulting the cover and closed-vent system requirements of EPA standards, such as OOOO and OOOOa and NESHAP HH. For ease of implementation, these requirements provide more detail than the UDEQ requirements in both the issued site-specific approval orders and the Utah Oil and Gas Rules but are comparable on balance with the UDEQ requirements for storage vessels and closed-vent systems.

3. VOC Emission Control Devices

For existing, new, and modified sources that are required to control VOC emissions from the collection of all storage vessels, glycol dehydrators and pneumatic pumps, we are finalizing requirements in 40 CFR 49.4177 (VOC emission control devices) that each owner or operator follow the manufacturer's written operating instructions, procedures and maintenance schedules to ensure the use of good air pollution control practices for minimizing emissions from each enclosed combustor and flare. Each flare must be designed and operated according to the requirements of 40 CFR 60.18(b). Each enclosed combustor must be designed and operated to reduce the mass content of the VOC in the natural gas routed to it by at least 95.0 percent continuously. The control efficiency required for each VOC emissions control device is the same as the Utah Oil and Gas Rules.

We recognize that the site-specific approval orders issued to existing sources under the Utah Permit Requirements require control devices to meet 98 percent VOC control efficiency. But we have concluded that the differences between this U&O FIP, the Utah Oil and Gas Rules, and the Utah Permit Requirements are minimal, and all were designed to achieve a consistent result. The UDEQ requires permittees of minor oil and natural gas sources to show compliance with 98.0 percent VOC control device control efficiency by routing all exhaust gas/vapors (from the storage vessels, glycol dehydrators or pneumatic pumps) to the operating combustor, operating the device according to the manufacturer's written instructions when gases/vapors are routed to it, operating the device with no visible emissions, and by performing tests to visually determine smoke emissions according to EPA Method 22 at 40 CFR part 60, appendix A. The Utah Oil and Gas Rules require at least 95.0 percent VOC control efficiency and do not specify methods to ensure no visible emissions but refer to NSPS OOOOa for demonstrating compliance with the control efficiency requirements. We note that combustion devices can be designed to meet 98.0 percent control efficiencies, and can control emissions by 98.0 percent or more, on average, in practice when properly operated.[89] Combustion devices designed to meet 98.0 percent control efficiency may not, however, be able to meet this efficiency level continuously in practice, due to factors such as the variability of field conditions and downtime.

During development of NSPS OOOO and OOOOa, 95.0 percent control efficiency was determined to be the best system of emission reduction (BSER) able to be continuously achieved by affected facilities (*e.g.,* storage vessels, centrifugal compressors) nationwide. The EPA is aware that enclosed combustors and flares may be capable of achieving instantaneous control efficiencies greater than 95.0 percent,[90] but in determining BSER the EPA must be confident that the control efficiency can be achieved continuously by affected facilities nationwide to which it applies. We are confident that combustors and flares can meet at least 95.0 percent VOC control efficiency on a continuous basis when they are designed, monitored and operated in a way that ensures effective performance on a continuous basis. While the EPA is aware that combustion devices commonly used to control VOC-containing gas streams are capable of demonstrating greater than 98.0 percent continuous VOC control efficiency in a controlled performance testing environment, under ideal conditions, based on widespread and readily available manufacturer test data,[91] we are not confident that the devices can achieve 98.0 percent continuous VOC control efficiency in the field without stronger flare performance requirements than are currently in effect today.[92]

We are requiring that all flares installed per this rule be designed and operated in accordance with applicable requirements in 40 CFR 60.18(b).[93] We are requiring that all enclosed combustors installed per this rule be models: (1) that have been tested by the manufacturer in accordance with specific requirements in NSPS OOOO and OOOOa; or (2) for which the owner or operator has conducted performance testing according to the requirements in NSPS OOOO and OOOOa. The Utah Oil and Gas Rules require that compliance for VOC control devices be demonstrated by meeting the performance test methods and procedures in NSPS OOOO. The Utah Oil and Gas Rules do not distinguish between flares and enclosed combustors. We determined, though, that it was important to have specific requirements for the different types of control devices that may be present at oil and natural gas sources on Indian country lands within the U&O Reservation, because EPA standards including NSPS OOOO and OOOOa and NESHAP HH make such distinctions for legal and practical enforceability. Therefore, although for ease of implementation this FIP's requirements for VOC control devices to demonstrate compliance with the control efficiency requirements are more detailed than the state's, they are comparable on balance with the Utah Oil and Gas Rules that reference such requirements in NSPS OOOO, as well as with NSPS OOOO and OOOOa and NESHAP HH.

We determined that certain work practice and operational requirements are also necessary for the practical enforceability of the VOC emission reduction requirements for flares or enclosed combustors. We are requiring that flares and enclosed combustors be operated within specific parameters to ensure the effective control of VOC emissions.[94] Specifically, we are requiring that each owner or operator ensure that each enclosed combustor or flare is: (1) operated at all times that emissions are routed to it; (2) equipped and operated with a liquid knockout system to collect any condensable vapors (to prevent liquids from going through the control device); (3) equipped and operated with a flashback flame arrestor; (4) equipped and operated with a continuous burning pilot flame, or an electronically controlled automatic ignition device; (5) equipped with a monitoring system for continuous recording of the parameters that indicate proper operation of each continuous burning pilot flame or electronically controlled automatic ignition device, such as a chart recorder, data logger or similar device, or connected to a Supervisory Control and Data Acquisition (SCADA) system, to monitor and document proper operation of the enclosed combustor or flare; (6) maintained in a leak-free condition; and (7) operated with no visible smoke emissions. These work practice and operational requirements are comparable to requirements of the Utah Oil and Gas Rules with respect to operation of the control devices with no visible emissions.

To ensure legal and practical enforceability, other work practice and operational requirements in this U&O FIP are different or more prescriptive than the Utah Oil and Gas Rules in several areas. For example, the Utah Oil and Gas Rules require all VOC emissions control devices simply to be equipped and operated with an operational automatic ignition device. This U&O FIP, on the other hand, requires each enclosed combustor or flare to be equipped and operated with either a continuous burning pilot flame or an electronically controlled automatic ignition device. Further, under this FIP all enclosed combustors and flares must be equipped with a monitoring system for continuous measurement and recording of the parameters that indicate proper operation of each continuous burning pilot flame or electronically controlled automatic ignition device, such as a chart recorder, data logger or similar device, or connected to a SCADA system to monitor and document proper operation of the device. The work practice and operational requirements for VOC control devices in this U&O FIP were developed by considering the UDEQ requirements for VOC control devices, in combination with consulting the work practice and operational requirements for control devices in EPA standards, including NSPS OOOO and OOOOa and NESHAP HH. Regarding

[89] The EPA has reviewed performance tests submitted for 19 different makes/models of combustor control devices and confirmed they meet the performance requirements in NSPS subpart OOOO and NESHAP subparts HH and HHH. All reported control efficiencies were above 99.9 percent at tested conditions. EPA notes that the control efficiency achieved in the field is likely to be lower than the control efficiency achieved at a bench test site under controlled conditions, but these units should be able to continuously meet a 95.0 percent control efficiency level when they are designed, monitored and operated in a way that ensures effective performance on a continuous basis. See Combustion Device Performance Testing Summary Table in the docket for this rule.

[90] See ''Oil and Natural Gas Sector New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants reviews, Parts 60 and 63, Response to Public Comments on Proposed Rule, 76 FR 52738 (Aug. 23, 2011), available at *https://www.regulations.gov* (Docket ID EPA–HQ–OAR–2010–0505 (Section 2.5.4, pages 127–128; Section 3.4.1, pages 294–295; and Section 3.5.1, pages 302–303)).

[91] See Combustion Device Performance Testing Summary Table in the docket for this rule.

[92] The Oil and Natural Gas Sector Climate Review Proposed Rule is soliciting comment and information that would help us better understand the cost, feasibility, and emission reduction benefits associated with establishing a 98 percent control efficiency requirement for flares in the Crude Oil and Natural Gas source category, including information on the level of performance being achieved in practice by flares in the field, what conditions or factors contribute to malfunctions or poor performance at these flares, and what measures the EPA could or should require in order to ensure that flares perform at a 98 percent level of control. *See* 86 FR 63110 (Nov. 15, 2021).

[93] 40 CFR 60.18(b) for flares requires compliance with 40 CFR 60.18(c) through (f).

[94] The necessity of such a requirement was discussed in detail in the preamble and Technical Support Documents to the proposed and final NSPS OOOO. These documents can be found in the docket for the NSPS OOOO rulemaking (Docket ID EPA–HQ–OAR–2010–0505), available at *https://www.regulations.gov.*

the requirement to equip enclosed combustors and flares with either a continuous burning pilot flame or an electronically controlled automatic ignition device, provided there is a monitoring system to indicate proper operation of the device, the EPA has maintained the position as recently as 2016 that without a continuous ignition source, there may be periods of uncontrolled emissions, and continuous ignition sources are designed to combust the flammable portion of the gas stream, even if the gas stream has a low BTU content.[95] Therefore, we have maintained that automatic ignition devices alone may not be reliable in the field to ensure that there is an ignition source at all times gas is flowing to a control device, and EPA standards, such as NSPS OOOO and OOOOa, have commonly required that enclosed combustors be equipped with continuous burning pilot flames and continuous parameter monitoring systems to ensure the presence of a flame at all times a gas stream is routed to the control device. Additionally, since the final FIP requires compliance with 40 CFR 60.18(c)(2)[96] of the General Provisions for 40 CFR part 60 when using a flare, a continuous pilot flame is required, and we have determined that an equivalent requirement should be applicable to enclosed combustion control devices used for controlling emissions from storage vessels and other equipment at affected oil and natural gas sources.

We recognize that the UDEQ requires automatic ignition devices on all combustion devices. In the interest of establishing regulations on Indian country lands within the U&O Reservation that are comparable on balance with the UDEQ requirements, we are finalizing a hybrid approach that allows owners and operators required to control VOC emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps the option to use devices that comply with EPA standards (continuous burning pilot), or to use electronically controlled automatic ignition devices if the control device is also equipped with a system that can indicate to the owner and operator that the automatic ignition device is not operating properly while gas is being routed to the control device. We expect that these requirements for control devices will achieve a result comparable to the requirements for VOC control devices in the Utah Oil and Gas Rules and will ensure that the control device is operated properly to achieve the required control efficiency while providing consistency with EPA policy regarding flares and combustors.

Section 49.4177 allows owners or operators of oil and natural gas sources, on receiving written approval, to use control devices other than an enclosed combustor or flare, provided they continuously achieve at least 95.0 percent VOC control efficiency. We expect that this provision will allow owners and operators to take advantage of technological advances in VOC emission control in the oil and natural gas industry, and that it will provide us with valuable information on new control technologies.

4. Fugitive Emissions Control

For existing, new, and modified sources, we are finalizing LDAR requirements in 40 CFR 49.4178 (Fugitive emissions VOC emission control requirements) that each owner or operator of an oil and natural gas source conduct periodic inspections of the source to detect leaks from fugitive emissions components and repair them if either of the following is true: (1) the collection of fugitive emissions components is located at an oil and natural gas source that is required to control VOC emissions according to 40 CFR 49.4173 through 49.4177 of this FIP (*i.e.,* the source-wide potential for VOC emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps is equal to or greater than 4 tpy, as determined according to 40 CFR 49.4173(a)(1)); or (2) the collection of fugitive emissions components is located at a well site, as defined in 40 CFR 60.5430a, that at any time has total production greater than 15 boe per day based on a rolling 12-month average.[97] Owners and operators of the collection of fugitive emissions components for which neither of the aforementioned conditions are true have the option to either (1) implement a program of periodic fugitive emissions inspections and repair, or (2) demonstrate that the total daily oil and natural gas production of the collection of all wells producing to the well site is at or below 1 boe per day, based on a 12-month rolling average, calculated according to specific procedures specified in 40 CFR 49.4178(e). Owners and operators of the collection of fugitive emissions components at an oil and natural gas source that is subject to the fugitive emissions monitoring requirements of NSPS OOOOa are exempt from this FIP's fugitive emissions monitoring requirements for those components.

We are finalizing a definition of ''fugitive emissions component'' in 40 CFR 49.4171, consistent with the approach in NSPS OOOOa, that includes valves, connectors, open-ended lines, pressure relief devices, flanges, covers and closed-vent systems not subject to 40 CFR 49.4173 through 49.4175, thief hatches or other openings on controlled storage vessels not subject to 40 CFR 49.4173, compressors, instruments and meters.[98] Each owner or operator is required to develop and implement a Reservation-wide fugitive emissions monitoring plan for all of its affected oil and natural gas sources on Indian country lands within the U&O Reservation that must include the following elements, at a minimum:

(1) Conduct an initial monitoring of fugitive emissions components at each affected source within 12 months of the effective date of the rule.

(2) Conduct subsequent monitoring once every 6 months after the initial monitoring for fugitive emissions components at oil and natural gas sources.

(3) Describe the fugitive emissions detection monitoring method to be used (limited to onsite optical gas imaging instruments, with a leak defined as any visible emissions using an optical gas imaging instrument, EPA Reference Method 21, with an instrument reading of 500 parts per million volume (ppmv) VOC defined as a leak, or another method approved by the EPA other than optical gas imaging or EPA Reference Method 21).

(4) Identification of manufacturer and model number of any leak detection equipment to be used.

[95] The EPA's Response to Public Comments on the EPA's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources. 40 CFR part 60, subpart OOOOa. May 2016. Chapter 11—Compliance. Comment Excerpt Number: 17. Pages 188–191 (Docket ID EPA–HQ–OAR–2010–0505–7632), available at *https://www.regulations.gov,* accessed Mar. 14, 2022.

[96] Per 40 CFR 60.18(b).

[97] As explained earlier, the Oil and Natural Gas Sector Climate Review Proposed Rule proposes a different approach for LDAR applicability based on the level of facility wide methane fugitive emissions. We are finalizing these requirements in the interest of taking action now to reduce VOC emissions on the Indian country lands within the U&O Reservation and recognizing the advantages of maximizing emissions reductions while providing a measure of consistency with the UDEQ and federal requirements that are in effect today. We may revisit this rulemaking in the future based on any final action we take under CAA section 111 with the Oil and Natural Gas Sector Climate Review rulemaking.

[98] Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

(5) Procedures and timeframes for identifying and repairing components from which leaks are detected, including a requirement to repair any identified leaks from components that are safe to repair and that do not require source shutdown within 30 days of discovering a leak, and identification of timeframes (which must be no later than the next required monitoring event after discovering the leak) to repair leaks that are designated as difficult-to-monitor or unsafe-to-monitor, or which require source shutdown. If the repair or replacement of a fugitive emissions component designated difficult-to-monitor or unsafe-to-monitor is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or shut-in, or would be unsafe to repair [99] during operation of the unit, the repair or replacement must be completed during the next scheduled compressor station shutdown, well shutdown, well shut-in, after a planned vent blowdown, or within 2 years, whichever is earlier.

(6) Procedures for verifying effective repair of leaking components, no later than 30 days after repairing a leak.

(7) Specific training and experience needed to perform inspections.

(8) Description of procedures for calibration and maintenance of any fugitive emissions monitoring device to be used.

(9) Standard monitoring protocols for each type of typical affected source (*e.g.,* well site, tank battery, compressor station), including a general list of component types that will be inspected and what supporting data will be recorded (*e.g.,* wind speed, detection method device-specific operational parameters, date, time, and duration of inspection).

We are finalizing in 40 CFR 49.4179 an exemption for source owners/operators from having to monitor and repair a fugitive emissions component under certain circumstances: (1) the contacting process stream only contains glycol, amine, methanol or produced water; or (2) the component to be inspected is buried, insulated in a manner that prevents access to the components by a monitor probe or optical gas imaging device, or obstructed in a manner that prevents access by a monitor probe or optical gas imaging device.

The fugitive emissions LDAR requirements in this U&O FIP are designed to be consistent with those in NSPS OOOOa. In developing the final FIP LDAR requirements, we also reviewed the UDEQ requirements. For existing, new, and modified sources subject to the Utah Oil and Gas Rules, the LDAR requirements were designed to be procedurally consistent with NSPS OOOOa, though the applicability threshold is different. The UDEQ's site-specific approval orders, a general approval order (GAO) for crude oil and natural gas well sites and tank batteries,[100] and the Utah Oil and Gas Rules all require implementation of an LDAR program at facilities that are required to control storage vessel, dehydrator, and/or pneumatic pump emissions. The Utah Oil and Gas Rules require semi-annual fugitive emissions monitoring and repair for any affected source. Existing oil and natural gas sources that were authorized under the UDEQ's site-specific approval orders are required to conduct fugitive emissions monitoring and repair at frequencies ranging from annual to quarterly. Existing oil and natural gas sources that are authorized under the UDEQ's GAO are subject to fugitive emissions monitoring at varying frequencies based on production levels and number of leaks detected.

The final FIP applicability threshold is consistent in part with the UDEQ's LDAR applicability threshold, though the final FIP also requires any additional sources where daily production exceeds 15 boe per day to conduct an LDAR inspection program, which is consistent in part with NSPS OOOOa. The LDAR inspection frequency requirements of this U&O FIP are the same as the Utah Oil and Gas Rules and NSPS OOOOa. For oil and natural gas sources that may have obtained coverage under the UDEQ's approval orders or the GAO, we concluded that the UDEQ's LDAR inspection frequency requirement is different than the LDAR inspection frequency requirements for oil and natural gas sources under this U&O FIP, which may require monitoring frequencies for only certain sources that are equivalent to this U&O FIP.

We are finalizing a provision allowing for the use of alternative methods of leak detection, other than EPA Reference Method 21 or optical gas imaging instrument, to demonstrate compliance with the fugitive emissions monitoring requirements, provided the method is approved by the EPA. We are finalizing language specifying that to be approved by the EPA, a demonstration that the alternative method achieves emissions reductions that equal or exceed those that would result from the application of either Method 21 or optical gas imaging instruments must be made and any proposed approval by the EPA will be subject to public notice and comment.

5. VOC Emissions Control Requirements for All Sources

Sections 49.4179 (VOC emission control requirements for tank truck loading), 49.4180 (VOC emission control requirements for pneumatic controllers) and 49.4181 (Other combustion devices) contain requirements for all existing, new, and modified existing oil and natural gas sources, regardless of source-wide or emission-unit-specific emissions. Like the requirements in Utah's Oil and Gas Rules for oil and natural gas sources in areas of the Basin where the EPA has approved the UDEQ to implement the CAA, the U&O FIP's requirements are as follows: (1) tank trucks used for transporting crude oil, condensate, intermediate hydrocarbon liquids or produced water must be loaded using bottom filling or submerged fill pipes; (2) all existing pneumatic controllers must meet the pneumatic controller standards in NSPS OOOO at 40 CFR 60.5390(b)(2) and (c)(2) and NSPS OOOOa at 40 CFR 60.5390a(b)(2) and (c)(2); and (3) all existing enclosed combustors, flares present and operating at sources on a voluntary basis—that is, those that are not required to control storage vessel, glycol dehydrator, and pneumatic pump emissions (per 40 CFR 49.4173 through 49.4175)—must be equipped with an electronically controlled automatic ignition device.

Our requirements for truck loading/unloading diverge in one respect from what the UDEQ is requiring in the Utah Oil and Gas Rule. The UDEQ requires that VOC emissions from tank truck loading and unloading at sources required to control storage vessel emissions be captured using a vapor capture line and routed to the onsite combustor or a separate combustor for VOC control. We are not finalizing an equivalent requirement at this time, as we did not receive sufficient cost and emissions reduction information during the public comment period for this rulemaking to sufficiently evaluate the cost effectiveness of such a requirement for the limited estimated emissions for truck loading/unloading on Indian country lands within the U&O Reservation, based on the UBEI2017-

[99] "Unsafe to repair" is defined in the final rule as meaning that operator personnel would be exposed to an imminent or potential danger as a consequence of the attempt to repair the leak during normal operation of the source.

[100] The docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709) contains an approval for coverage under the GAO for a Crude Oil and Natural Gas Well Site and/or Tank Battery (DAQE–MN149250001–14).

Update.[101] The inventory identifies 595 tpy VOC from truck loading/unloading. Assuming that the annualized cost to install a vapor capture line to an existing combustor is similar to that of routing pneumatic pump emissions to a combustor (approximately $1,627 per source) and assuming that there are approximately 2,165 sources that would be required to add a combustor, such a requirement to install an additional truck vapor capture line would result in high annualized costs relative to the VOC emissions reductions that would be achieved (over $6,000 per ton of VOC reduced per year).

Concerning pneumatic controllers, the U&O FIP adopts by reference the definitions of *natural gas-driven pneumatic controller* in NSPS OOOO and OOOOa (40 CFR 60.5430 and 60.5430a, which are identical) and requires owners/operators of affected pneumatic controllers (those controllers not subject to and controlled in accordance with the requirements for pneumatic controllers in NSPS OOOO or OOOOa) to meet the standards established for pneumatic controllers in NSPS OOOO. We are finalizing the requirement that owners/operators of affected controllers meet the tagging requirements in 40 CFR 60.5390(b)(2), 60.5390(c)(2), except that the month and year of installation, reconstruction, or modification is not required. This exception is consistent with the Utah Oil and Gas Rules.

Lastly, for existing enclosed combustors, flares present and operating at sources that would not be required to comply with the substantive VOC emissions control requirements of sections 40 CFR 49.4173 through 49.4177, we are finalizing a requirement that those voluntarily operated control devices be equipped with an electronically controlled automatic ignition device. This approach is the same as the requirements of the Utah Oil and Gas Rules, which require automatic igniters on all existing combustion devices. In contrast to the 40 CFR 49.4177 (VOC Emission Control Devices) requirements for devices used to comply with this FIP's substantive VOC emissions control requirements, we determined that it would be unreasonable to require voluntarily operated devices to have a system to monitor proper operation of devices used to ensure the presence of a flame at all times a gas stream is routed to the device, and that such a requirement would result in requirements for such sources on Indian country lands within the U&O Reservation that are not comparable to requirements for such sources in areas where the EPA has approved the UDEQ to implement the CAA.

G. Monitoring and Testing Requirements

For existing, new, and modified sources, in 40 CFR 49.4182 (Monitoring and testing requirements) we are requiring each owner or operator to conduct source monitoring necessary for the practical enforceability of the U&O FIP's VOC emission reduction requirements, including: (1) monthly inspections of each cover and closed-vent system, including storage vessel openings, thief hatches, pressure relief valves, and bypass devices, to ensure proper condition and functioning and for defects that can result in air emissions consistent with the procedures in 40 CFR 60.5416a(c) [NSPS OOOOa], correcting or repairing any defects identified within 30 days of identification; and (2) monthly inspections of each VOC emissions control device to ensure proper functioning and demonstrate compliance with the VOC emissions control device requirements by (a) checking the control device and parameter monitoring system for proper operation, including system integrity and leak-free operation, at least once per calendar month; (b) responding to any indication of pilot flame failure and ensuring the pilot flame is relit as soon as practicably and safely possible after discovery; and (c) monitoring visible emissions consistent with the requirements in 40 CFR 60.5412(d), using EPA Method 22 visual emissions testing to demonstrate there are no visible smoke emissions.

These monitoring requirements are comparable on balance to those in the Utah Permit Requirements and Utah Oil and Gas Rules, with some exceptions made to ensure legally and practicably enforceable control of VOC emissions. For example, the Utah Permit Requirements and Utah Oil and Gas Rules require installation and operation of an automatic ignition device and operations with no visible emissions for all VOC control devices, but there are no corresponding monitoring requirements to demonstrate compliance with those requirements. We expect that this FIP's monitoring requirements for ensuring there is a constant ignition source when gas is flowing to the control device and for visible emissions testing will provide legal and practical enforceability.

H. Recordkeeping Requirements

For existing, new, and modified sources, in 40 CFR 49.4183 (Recordkeeping Requirements) we are requiring that each owner or operator of an affected oil and natural gas source keep specific records to be made available upon request, in lieu of voluminous reporting requirements. The records that must be kept include required inspections, measurements, monitoring results, emissions calculations, and deviations or exceedances of rule requirements and corrective actions taken, as well as any manufacturer specifications and guarantees or engineering analyses. These recordkeeping requirements provide legal and practical enforceability for the control and emission reduction requirements of this rule.

I. Notification and Reporting Requirements

For existing, new, and modified sources, we are finalizing in 40 CFR 49.4184 (Notification and reporting requirements) to require that each owner or operator of an affected oil and natural gas source prepare and submit an annual compliance report, with the initial report due April 1st of the calendar year following the effective date of the final rule and must cover all affected operations for the previous calendar year on and after the effective date of the final rule. Subsequent annual reports are due on the same date each year as the date the initial annual report was submitted and must cover all affected operations for the previous calendar year. The report must include a summary of deviations or exceedances of any requirements of the final FIP and the corrective measures taken for a specific subset of targeted required records for each enclosed combustor or flare, each cover and closed-vent system, fugitive emissions monitoring inspection, and each high-bleed controller, as identified in the rule. Annual reports may coincide with Title V, NSPS OOOO or OOOOa or NESHAP HH reports as long as all the required elements of the annual report are included. Additionally, a report of results must be submitted for any performance test we require. These reporting requirements provide legal and practical enforceability for the control and emission reduction requirements of this rule.

[101] The Oil and Natural Gas Sector Climate Review Proposed Rule is soliciting comment and information that would help us better understand the cost, feasibility, and emission reduction benefits associated with controlling truck loading/unloading emissions. As with LDAR applicability, we may revisit this rulemaking in the future based on any final action we take under CAA section 111 with the Oil and Natural Gas Sector Climate Review rulemaking.

V. Significant Changes Since Proposal

This U&O FIP, which is intended to address winter air quality impacts from ozone pollution, contains a common set of VOC emissions control requirements for certain existing, new, and modified oil and natural gas sources on the Indian country lands within the U&O Reservation. We consulted existing federal CAA oil and natural gas source category standards in developing the VOC emissions control requirements of this U&O FIP. To make VOC emissions control requirements across the Basin consistent, this U&O FIP goes beyond the federal standards in some cases, regulating equipment and activities that are not covered by those standards but that are regulated by the UDEQ. Such equipment and activities include small, remote glycol dehydrators; low throughput storage vessels; tank truck loading and unloading; and certain voluntarily operated control devices. Applicability of the requirements, including for equipment and activities that are regulated by the federal standards, is also consistent with the applicability for equivalent equipment and activities regulated by the UDEQ.

As previously mentioned, the streamlined construction authorization mechanism in the National O&NG FIP applies on the Indian country portions of the U&O Reservation that are part of the Uinta Basin Ozone Nonattainment Area, as a result of our recent separate action amending the National O&NG FIP. Such true minor sources are required to register and comply with the eight federal standards in the National O&NG FIP, as applicable, to meet the preconstruction permitting requirements of the Federal Indian Country Minor NSR Program. Compliance with the eight federal standards in the National O&NG FIP, as applicable, does not relieve the owners/operators from the other applicable VOC control requirements of this U&O FIP, except that this U&O FIP exempts certain equipment and activities from it that are in compliance with the applicable requirements of the National O&NG FIP.

We have made some changes to the requirements in the U&O FIP after considering public comments and evaluating more recent emissions inventories and air quality information. More details on our evaluation of available information and reasons for these decisions are described in our summary of responses to comments in Section VI of this preamble, and in the RIA and Response to Public Comments documents for this final rule.[102]

A. Final Rule Effective Date and Compliance Deadline

In the proposed U&O FIP, we stated that we might issue a final action based on the proposal as soon as the date of publication of a final U&O FIP. We believed that there would be ''good cause,'' within the meaning of 5 U.S.C. 553(d)(3), to make the final rule effective as soon as published, if that proved necessary to ensure that this rule began to provide emission reductions before the next winter ozone season. As discussed above in Section II.D., winter ozone in the Uinta Basin is a serious public health problem, which this final rule is intended to help address. In addition, the reductions provided by this rule are an integral part of the Agency's strategy to address the air quality problem on the Indian country lands within the U&O Reservation while maintaining a permitting mechanism that allows appropriate continued oil and natural gas production. The primary other component of that strategy is a separate action to amend the National O&NG FIP to extend its geographic coverage to the Indian country portions of the U&O Reservation that are part of the Uinta Basin Ozone Nonattainment Area. Over the long term, we are relying on the VOC emissions reductions achieved through this action to ensure that the previous extension of the scope of the National O&NG FIP does not jeopardize air quality.

After careful consideration of the comments received, and of the requirements under the Congressional Review Act (CRA) specifying that a major rule may become effective no earlier than 60 days after it is published in the **Federal Register**,[103] the EPA is finalizing an effective date 60 days after the final rule is published in the **Federal Register**.

We proposed to require compliance by oil and natural gas sources existing as of the effective date of the final rule no later than 18 months after the effective date of the final rule. We have revised that compliance period to a 12-month compliance deadline. The proposed 18-month compliance period was informed by what we had learned about the time needed for sources in areas of the Basin where the EPA has approved the UDEQ to implement the CAA to comply with Utah's requirements for oil and natural gas sources. We had been informed by UDEQ compliance staff that the majority of existing oil and natural gas sources in areas of the Basin where the EPA has approved the UDEQ to implement the CAA that had been required to install VOC emission control retrofits in had completed the required retrofits within 9 months of the effective dates of their minor source approval orders, ahead of the 18-month deadline in UDEQ approval orders for operators to notify the UDEQ of the status of retrofit construction.[104] The UDEQ estimated that approximately 1,600 existing sources had been required to install retrofits to control emissions from the collection of all storage vessels, glycol dehydrators, and/or pneumatic pumps on non-Indian country lands in the Uinta Basin. For the proposal, on the other hand, we estimated that there were approximately 2,100 sources on Indian country lands within the U&O Reservation that would be subject to such requirements in this U&O FIP. We considered it likely in light of this larger number of sources, and the presumably finite availability of equipment and personnel, that owners and operators would need longer than 9 months to complete the necessary retrofits to the greater number of Indian country sources. Therefore, we proposed an 18-month compliance deadline for the U&O FIP as reasonable to accommodate the challenges of procurement of equipment and labor to complete the retrofits of a larger number of sources. Using the UBEI2017-Update, we now estimate that 2,165 existing sources on the Indian country lands within the U&O Reservation will be required to install retrofits to control emissions from the

[102] These documents can be found in the docket for this rulemaking (Docket ID EPA–R08–OAR–2015–0709).

[103] Id. at 5 U.S.C. 801(a)(3)(A). This rule is considered an economically significant rule under Executive Order 12866, as a rule that imposes costs or generates benefits of at least $100 million per year, which is the same economic threshold applied in defining what constitutes a ''major rule'' under the CRA (one that ''is or is likely to result in . . . an annual effect on the economy of $100,000,000 or more.'').

[104] Email correspondence with UDEQ staff regarding their source inventory and experiences regulating existing oil and natural gas sources in areas of the Basin where the EPA has approved the UDEQ to implement the CAA is included in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709). UDEQ compliance staff target each new approval order for inspection within 18 months of the date it is issued. They document the status of construction at the time of inspection and note whether the permitted source has provided a notification of construction status, which is required within 18 months of the date the approval order is issued. UDEQ compliance staff have inspected hundreds of such existing oil and natural gas sources without observing any compliance issues with the 18-month notification requirement. While UDEQ compliance staff do not compile this information into any readily available summary format, details about the status of construction are included in the inspection report for each source.

collection of all storage vessels, glycol dehydrators, and pneumatic pumps under this U&O FIP, which is only slightly more than the number of existing affected sources estimated for the proposed FIP using the UBEI2014.

Although the number of estimated affected sources is still higher than the number in areas where the EPA has approved the UDEQ to implement the CAA, after considering public comments received on the proposed 18-month compliance deadline and the demonstrated need for more near-term air quality benefits to improve air quality in and around the U&O Reservation, we have revised the proposed 18-month compliance period to a 12-month compliance period from the effective date of the rule. In the EPA's judgment, this shorter compliance schedule (especially when combined with the 60-day effective date) will sufficiently accommodate the potentially limited availability of equipment and personnel, and thus still reasonably allow industry to comply with the new requirements in a timely manner, while also ensuring that meaningful reductions will be achieved that will help make progress toward future attainment. Further, potentially affected owners and operators have been on notice of the possibility that these rules might come into effect since the proposed FIP was published in January 2020.

We also enhanced the final FIP to specify the process the EPA would take to decide requests for extension of the compliance period, in particular adding the requirement that the request be submitted before the compliance deadline, identify the specific provisions for which an extension is being requested and include an alternative compliance deadline, and provide a rationale for the request with supporting information explaining how the operator will effectively meet all applicable requirements after the requested alternative compliance deadline.

B. Triennial Emissions Inventory

In the proposed FIP we contemplated establishing the due date for the submittal of annual emissions covering the first triennial inventory year 2020 as October 1, 2021, to allow operators time to set up an appropriate emissions tracking and reporting system. However, given the time that has elapsed since the proposal, we are revising the proposal to require the first triennial emissions inventory to cover calendar year 2023, with the first inventory due on April 15, 2024, and thereafter, every three years, the inventory will be due on April 15th of the year following the inventory year. This is in line with the UDEQ's triennial emissions inventory collection, and the schedule for the NEI. This revised schedule will also allow additional time for operators to set up an appropriate emissions tracking and reporting system, according to the instructions we will make available on our website for the rule once it is finalized.

C. Streamlined Construction Authorization

In the proposed FIP we contemplated moving the authority for streamlined construction authorization mechanism of true minor oil and natural gas sources on the Indian country portions of the U&O Reservation that are part of the Uinta Basin Ozone Nonattainment Area in the National O&NG FIP (through 40 CFR part 49, subpart K) to this FIP, so as to consolidate air quality requirements for oil and natural gas sources in the Indian country portions of the U&O Reservation that are part of the Uinta Basin Ozone Nonattainment Area within one part of the Code of Federal Regulations, which we believed could provide a more efficient and user-friendly approach. However, we have decided not to finalize that approach in this FIP because, after further consideration, including consideration of public comments received, we believe that modifying the National O&NG FIP is unnecessary.

D. Applicability

In the proposed FIP, we defined some terms, such as storage tank, pneumatic pump, pneumatic controller, and fugitive emissions component, in a way that were different from the definitions of equivalent equipment and activities in NSPS OOOO and OOOOa. The proposed FIP was designed in part for consistency with NSPS OOOO and OOOOa and the Oil and Gas CTG, and for consistency with the Utah Oil and Gas Rules (which were also designed for consistency with NSPS OOOO and OOOOa). After considering public comments received, and for ease of implementation and compliance, we have revised the proposed definitions, and are finalizing definitions that are consistent with those in NSPS OOOO and OOOOa.

Another difference with NSPS OOOO and OOOOa and the Oil and Gas CTG that was identified in comments on the proposed FIP is in the method used to calculate VOC emissions from the collection of all storage vessels to determine applicability of the control requirements for storage vessels, glycol dehydrators and pneumatic pumps in 40 CFR 49.4173 through 49.4177. We proposed that VOC emissions from the collection of all storage vessels should be calculated based on uncontrolled actual emissions. To provide consistency with NSPS OOOO and OOOOa and the Oil and Gas CTG, we are finalizing requirements that VOC emissions from the collection of all storage vessels be calculated based on potential emissions, which may account for enforceable control requirements already applicable to certain storage vessels. The Utah Oil and Gas Rules require all storage vessels located at a well site that are in operation as of January 1, 2018, with a site-wide throughput of 8,000 bbl or greater of crude oil or 2,000 bbl or greater of condensate per year on a rolling 12-month basis, to control emissions unless an exemption applies that total VOC emissions from the collection of all storage vessels are demonstrated to be less than 4 tpy of uncontrolled actual emissions (defined as actual emissions or the potential to emit without considering controls) on a rolling 12-month basis. Emissions to meet the exemption must be calculated using direct site-specific sampling data and any software program or calculation methodology in use by industry that is based on AP–42 Chapter 7. A separate provision allows controls to be removed after a minimum of one year of operation if source-wide throughput is less than 8,000 bbl crude oil or 2,000 bbl condensate on a rolling 12-month basis or uncontrolled actual VOC emissions are demonstrated to be less than 4 tons per year. For sources that operate only storage vessels and not glycol dehydrators or pneumatic pumps, the proposed 8,000 bbl of crude oil/2,000 bbl of condensate throughput applicability threshold for control of storage vessel emissions was the same as the control applicability threshold for storage vessels in the UDEQ's recently adopted Utah Oil and Gas Rules. However, based on public comments received on the proposed rule, we decided not to finalize the production-based threshold for oil and natural gas sources with only storage vessels and no glycol dehydrators or pneumatic pumps. Several commenters expressed the view that, while they appreciated the effort to establish consistent requirements across all areas of the Basin, determining applicability for VOC combustion control requirements would be simpler and more straightforward if applicability was based solely on the annual facility-wide VOC emissions threshold for storage vessels, glycol dehydrators and pneumatic pumps of 4 tpy.

We noted in the preamble to the proposed U&O FIP that in January 2019, the Utah Air Quality Board approved an additional rule in the Utah Administrative Code Chapter R307–500 Series (Oil and Gas) at R307–511 to manage associated gas from a completed oil well by either routing it to a process unit for combustion, routing it to a sales pipeline, or routing it to a VOC control device, except for emergency release situations. This rule was approved after we had drafted and evaluated the emissions reductions and costs of the provisions in the proposed U&O FIP. We noted our intent to evaluate and consider incorporating equivalent associated gas requirements in a final U&O FIP. After careful consideration of the comments received and evaluation of the data used to estimate associated gas emissions in the UBEI2017-Update used to analyze the costs and benefits of this final FIP, we have decided not to finalize requirements to control associated gas emissions in the U&O FIP, because we do not have adequate information specific to the Uinta Basin operations to accurately assess and develop cost-effective requirements.

In the proposed U&O FIP, we based the applicability of the requirement to implement a semiannual fugitive emissions monitoring program on whether the oil and natural gas source was required to control facility-wide emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps. After considering public comments on the proposed FIP, we have revised the proposed fugitive emissions monitoring applicability, and in the final rule are requiring semiannual fugitive emissions monitoring for each owner or operator of an oil and natural gas source where either of the following is true: (1) As proposed, the collection of fugitive emissions components is located at an oil and natural gas source that is required to control VOC emissions according to 40 CFR 49.4173 through 49.4177 of this FIP (*i.e.,* the source-wide potential for VOC emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps is equal to or greater than 4 tpy, as determined according to 40 CFR 49.4173(a)(1)); or (2) As revised, the collection of fugitive emissions components is located at a well site, as defined in 40 CFR 60.5430a, that at any time has total production greater than 15 boe per day based on a rolling 12-month average.

The Uinta Basin generally encompasses an area of over 6,800 square miles with hundreds of miles of dirt roads connecting over 10,000 oil and natural gas wells. According to the Updated 2017 Uinta Basin Emissions Inventory (UBEI2017-Update),[105] the average number of wells per well pad is 1.5. The inventory shows that fugitive emissions are the second highest VOC emissions source on Indian country lands within the U&O Reservation, at about 15,600 tpy. Studies have been conducted specific to the Uinta Basin that investigated the sources of VOC emissions from oil and natural gas production operations. Certain high emitting sources, or ''super-emitters,'' are likely due to abnormal process conditions.[106] Examples of abnormal process conditions, which could be persistent or episodic, include: failures of storage vessel control systems; malfunctions upstream of the point of emissions (for example, stuck separator dump valve resulting in produced gas venting from storage vessels); design failures (for example, vortexing or gas entrainment during separator liquid dumps); and equipment or process issues (for example, over-pressured separators, malfunctioning or improperly operated dehydrators or compressors).[107] A July 2017 study by Utah State University, TriCounty Health Department, and the UDEQ surveyed 400 oil and natural gas well pads using an IR camera for fugitive emissions detection at storage vessels and found that emissions plumes were detected at 37 percent of well pads where the storage vessels were controlled. A November 2018 Utah State University study employed a hybrid of both ground based and aerial IR detection methods. The study found that the majority of observed fugitive emissions plumes originated from storage vessels (over 75 percent) and that facilities where emissions were detected were primarily younger, high production facilities with more liquid storage vessels, and, in the case of the aerial observations only, that primarily produce oil. The study found that emissions that were more likely to be characterized as large were observed at well pads with controlled storage vessels. The emissions were observed upstream of the control device, from thief hatches, vents and piping on the tanks. The results of these two studies strongly suggest that a significant quantity of emissions from controlled storage vessels were not reaching the designated control device. Requiring owners and operators of oil and natural gas sources that are required to control storage vessel, dehydrator and pneumatic pump emissions to implement a LDAR program will help reduce fugitive emissions from well sites with controlled storage vessels. We acknowledge that the definition of fugitive emissions component in the final U&O FIP excludes valves, connectors, pressure relief devices, open-ended lines, flanges, covers, closed-vent systems, thief hatches, and other openings associated with storage vessels or closed-vent systems subject to the control requirements of 40 CFR 49.4173 and 49.4176. Those activities are subject to specific integrity monitoring requirements in 40 CFR 49.4182, discussed later in this section, to ensure that 100 percent of the emissions are routed either to a process or an emissions control device. However, the LDAR requirements of final 40 CFR 49.4177 do apply to components associated with storage vessels and closed-vent systems that are not subject to the requirements of 40 CFR 49.4173 and 49.4176. We expect that the combination of the LDAR requirements of final 40 CFR 49.4177 and the integrity monitoring requirements of final 40 CFR 49.4182 will effectively reduce VOC emissions from equipment leaks at oil and gas sources with controlled storage vessels.

We determined that to maximize VOC emissions reductions and the resulting expected improvements in air quality on the U&O Reservation and surrounding areas, finalizing a balance between the LDAR applicability thresholds of the Utah Oil and Gas Rules and the CTG is appropriate, as it will result in emissions reductions at more existing sources than if we finalized the proposed applicability threshold. It will not impose the requirement to implement an LDAR program at every oil and natural gas source on the Indian country lands within the U&O Reservation, which could potentially create a competitive disadvantage to operating on the Reservation, resulting

[105] UBEI2017-Update. The inventory and supporting analysis can be viewed in the docket for this rulemaking, Microsoft Excel spreadsheet titled, ''UO FIP cost and emissions analysis.xlsx'' (Docket ID No. EPA–R08–OAR–2015–0709).

[106] Zavala-Araiza, D., Alvarez, R. A., Lyon, D. R., Allen, D. T., Marchese, A. J., Zimmerle, D. J., & Hamburg, S. P.; ''Super-emitters in Natural Gas Infrastructure are Caused by Abnormal Process Conditions,'' *Nature Communications* 8, 14012 (2017).

''Storage Tank Emissions Pilot Project (STEPP): Fugitive Organic Compound Emissions from Liquid Storage Tanks in the Uinta Basin,'' Final Report to The Utah State Legislature (USU, TriCounty Health Dept, UDEQ, July 17, 2017) available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

''Hydrocarbon Emission Detection Survey of Uinta Basin Oil and Gas Wells''. November 2018. Bingham Research Center, Utah State University, available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

[107] The UBEI2017-Update has not accounted for the phenomenon of ''super-emitters.''

in potentially negative economic impacts for the Ute Indian Tribe and other mineral owners. We acknowledge that NSPS OOOOa currently contains two different LDAR inspection standards for well sites and gathering and boosting compressor stations controlling methane emissions and those controlling VOC emissions and that the EPA has published a proposed national rule to reduce methane and other pollutants from existing, new, and modified sources in the oil and natural gas industry that seeks to align those standards to require semiannual LDAR inspections for all well sites (*e.g.,* remove the exemption for low-production wells) and quarterly LDAR inspections for all compressor stations.[108] We also acknowledge that the rule proposes to establish new methane and VOC fugitive emissions monitoring standards for new and modified sources and similar methane fugitive emissions monitoring guidelines for existing sources.

We expect that the final LDAR requirements of this FIP will result in meaningful reductions in VOC emissions and ground-level ozone production, significantly furthering our main objective for this U&O FIP of improving air quality. We determined that, particularly for existing sources, in order to meet our goal to provide consistent requirements across the Uinta Basin, the LDAR inspection frequency requirements in this U&O FIP should provide a measure of consistency with the LDAR inspection frequency requirements in the Utah Oil and Gas Rules, as those rules apply prospectively to all oil and natural gas well sites on non-reservation Indian country lands in the Uinta Basin that are not already subject to site-specific approval orders or the GAO. If the sources in the Uinta Basin that are in areas where the EPA has approved the UDEQ to implement the CAA are also subject to the LDAR requirements of the NSPS OOOOa, the NSPS requirements supersede the UDEQ requirements if the UDEQ requirements are less stringent. Similarly, if the sources in the Uinta Basin that are regulated by the EPA on Indian country lands within the U&O Reservation are subject to the LDAR requirements of NSPS OOOOa, those sources are exempt from complying with the LDAR requirements in this U&O FIP. We may revisit this final action in the future based on any final action we take under CAA section 111 with the Oil and Natural Gas Sector Climate Review rulemaking to address application of LDAR at sources covered by this FIP in a manner similar to the final national rule's provisions for sources that it covers. Also, if the Uinta Basin Ozone Nonattainment Area's Marginal classification is reclassified (''bumped up'') to a Moderate nonattainment classification, or if air quality concerns otherwise warrant, we may conclude that further rulemaking is necessary or appropriate.

We proposed general language in the fugitive emissions provisions allowing for the use of methods of leak detection other than EPA Reference Method 21 or optical gas imaging instrument to demonstrate compliance with the fugitive emissions monitoring requirements, provided the method is approved by the EPA. We solicited information in the proposed U&O FIP on alternative methods of leak detection (*e.g.,* aerial) that could potentially achieve meaningful and more cost-effective reductions in fugitive VOC emissions that contribute to ozone formation, and whether any of these advanced monitoring technologies would be effective in the Uinta Basin and should be approvable as an alternative leak detection compliance method under a final U&O FIP. We also solicited input on the criteria that the EPA should consider in approving alternative leak detection compliance methods, including appropriate accuracy and quality assurance standards that alternative methods would need to meet to demonstrate equivalency to onsite optical gas imaging instruments or onsite EPA Reference Method 21. We noted that specific descriptions of the approach, frequency of monitoring, detection thresholds, limiting factors in detection, costs and availability for alternative leak detection methods would be helpful. We did not receive any new information on the costs and effectiveness of alternative leak detection methods during the public comment period. However, we did receive suggestions for criteria we should consider in approving alternative leak detection compliance methods to demonstrate equivalency to EPA Reference Method 21 or optical gas imaging. Based on those comments, we have added language to the final FIP specifying that to be approved by the EPA, a demonstration that the alternative method achieves emissions reductions that equal or exceed those that would result from the application of either Method 21 or optical gas imaging instruments must be made and any proposed approval by the EPA will be subject to public notice and comment.

Studies specific to the Uinta Basin have investigated the viability of leak detection method alternatives to conventional onsite instrument detection, including detection methods from an aerial platform. One study[109] employed a helicopter-based infrared camera at an elevation of approximately 50 meters above ground level to survey more than 8,000 oil and natural gas well pads in seven United States basins. The goal of this aerial survey was to assess the prevalence and distribution of hydrocarbon sources whose fugitive emissions were high enough to be labeled high-emitters. At each site with detected emissions, the survey team reported the site's location and the number and equipment type of each observed emission source. Survey results indicated that high-emitting sites constituted four percent of all the sites surveyed across the seven basins examined. In the Uinta Basin, 1,389 well pad facilities were flown over, and high emissions were observed at 6.6 percent of those well pads. Another previously discussed study[110] that employed a hybrid of both ground-based and aerial IR detection methods found that observations using an IR camera from a helicopter in winter were hampered by the cold land temperatures of the background against which the plumes would be observed. The ground-based part of this study, as previously discussed, showed a fairly high prevalence of observed emissions from controlled storage vessels.

We are finalizing the proposed provisions allowing operators to use

[108] *See* 85 FR 63110. Nov. 15, 2021. *Proposed Rule. Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* available at *https://www.regulations.gov* (Document ID #EPA–HQ–OAR–2021–0317–0001), accessed Mar. 14, 2022. The regulatory inconsistencies stem from the recent joint resolution under the Congressional Review Act that disapproved the 2020 Policy Rule. That rule, which was issued by the previous Administration, had eliminated important requirements to reduce methane and other air pollution from new and modified sources in the oil and natural gas source category. However, the joint resolution did not address a separate 2020 rule known as the ''Technical Rule,'' which remains in place today. The EPA is proposing to repeal amendments in the Technical Rule that exempted low-production well sites from monitoring fugitive emission; and changed VOC monitoring requirements at gathering and boosting compressor stations from quarterly to semi-annually.

[109] ''Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites,'' Environmental Science and Technology, 2016, 50 (9), pp 4877–4886, publication date Apr. 5, 2016, available at *http://pubs.acs.org/doi/abs/10.1021/acs.est.6b00705,* accessed Mar. 14, 2022.

[110] ''Hydrocarbon Emission Detection Survey of Uinta Basin Oil and Gas Wells''. Nov. 2018. Bingham Research Center, Utah State University, available at available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

alternative methods of leak detection, other than EPA Reference Method 21 or optical gas imaging instruments, to demonstrate compliance with the fugitive emissions monitoring requirements, provided the method is approved by the EPA. We added language specifying that to be approved by the EPA, a demonstration that the alternative method achieves emissions reductions that equal or exceed those that would result from the application of either Method 21 or optical gas imaging instruments must be made and any proposed approval by the EPA will be subject to public notice and comment. The total fugitive VOC emissions reduced does not account for emissions due to abnormal process operations, which was discussed earlier. Recognizing that technology used to detect, measure, and mitigate emissions is rapidly developing, on July 18, 2016, the EPA issued a request for information, (RFI) [111] inviting all parties to provide information on innovative technologies to accurately detect, measure, and mitigate emissions from the oil and natural gas industry. The intent of this notice was to solicit data supporting alternative approaches to limit emissions from this industry.

E. Monitoring and Testing

In response to several comments, and to clarify one provision, we made some changes to the proposed monitoring requirements for covers and closed vent systems and VOC emissions control devices to provide more consistency with NSPS OOOO and OOOOa. The proposed requirements for inspecting covers and closed vent systems were different than NSPS OOOOa in that they did not allow the option to demonstrate compliance by conducting optical gas imaging inspections on the same schedule as fugitive emissions inspections. We have added that option to the final FIP. Additionally, rather than adopt by reference the inspection requirements of NSPS OOOOa at 40 CFR 60.5416a(c), we incorporated streamlined inspection requirements for covers and closed vent systems into a common set of provisions, because the separate provisions in NSPS OOOOa are essentially the same. Although the preamble to the proposed rule explained that it would require that facilities ''ensure that each enclosed combustor or utility flare is. . . operated with no visible smoke emissions,'' in the proposed regulatory text we inadvertently mentioned only enclosed combustors, not flares, in the provision requiring owners and operators to verify on a monthly basis that there are no detectable smoke emissions. To make the regulatory text of the FIP consistent with the intent explained in the proposed rule as to flares, and also in response to comments that the FIP should provide more consistency with NSPS OOOO and OOOOa, the monitoring requirements being finalized today, consistent with NSPS OOOO and OOOOa, require Method 22 monitoring for all VOC control devices. We also streamlined the requirements to perform monthly inspections of the covers closed-vent systems and monthly inspections of the VOC emissions control devices, each separated by at least 15 days between each inspection, to provide operators the flexibility to schedule inspections in the same visit.

F. Recordkeeping and Reporting

In response to several comments, we also made some changes to the proposed recordkeeping requirements to provide more consistency with the records that the UDEQ requires of oil and natural gas sources, as well as with the records required by NSPS OOOO and OOOOa. Regarding annual reports, we made changes to clarify in the final FIP the April 1st due date of each annual report, and that the reporting period for the initial annual report will be the period beginning with the effective date of the final rule through the end of that calendar year. Additionally, in response to public comments that annual reporting should be limited to targeted records that most efficiently indicate the degree of compliance with the U&O FIP, we have specified a subset of required records that must be summarized in the annual report related to each enclosed combustor or flare, each cover and closed-vent system, fugitive emissions monitoring and each high-bleed pneumatic controller, including deviations from rule requirements and corrective actions taken to address deviations.

VI. Summary of Significant Comments and Responses

This section summarizes the significant public comments on the proposed FIP and our response to those comments as they related to the specific requirements being finalized today in this U&O FIP. More detailed summaries of the comments and our responses are available in the docket for this rulemaking.[112]

A. Major Comments Concerning Effective Date and Compliance Deadline

Comment: Industry commenters asserted that since the EPA has determined that the rule is an economically significant regulatory action subject to Office of Management and Budget Review under E.O. 12866, the rule must also be a ''major rule'' under the Congressional Review Act, which mandates that it may become effective no earlier than 60 days after it is published in the **Federal Register**.

Response: We agree and have finalized an effective date 60 days after publication in the **Federal Register**.

Comment: Industry commenters claimed that air quality studies in the Uinta Basin and available air quality data support that emissions reductions needed to attain the NAAQS only need to occur in the winter, rather than year-round as the EPA proposed, and claimed it was unreasonable and arbitrary that the EPA did not evaluate a seasonal regulatory option.

Response: We disagree that it was unreasonable or arbitrary not to evaluate a seasonal regulatory option to address elevated ozone and emissions reductions with this rulemaking. Through the stakeholder outreach we participated in during the rulemaking process, we heard feedback from the Ute Indian Tribe, the UDEQ, and oil and natural gas operators alike that consistent regulatory requirements across all areas in the Basin are important to ensuring a cohesive strategy to improve air quality, providing regulatory certainty and avoiding disadvantages to development in one area versus another. Based on verified ozone measurements during summer months at regulatory monitors in the Basin from 2017 to 2020, there have been at least a few exceedances of the 8-hour ozone daily maximum, and many other readings that have been close to the NAAQS. Imposing a seasonal control program for this rulemaking when the UDEQ requires year-round controls and the majority of the existing VOC emissions in the Basin are occurring on the Indian country lands within the U&O Reservation was not considered for several reasons. Doing so would continue inconsistent regulatory requirements across all areas in the Basin, potentially creating incentives to develop sources with higher emissions on the Reservation. Seasonal emissions reductions requirements would be complex to implement, enforce and quantify the effects to defensibly justify continued

[111] *See* 81 FR 46670 (July 18, 2016).

[112] Response to Public Comments. Proposed Federal Implementation Plan: Managing Emissions from Oil and Natural Gas Sources on Indian Country Lands within the Uintah and Ouray Indian Reservation in Utah. May 2021, available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

minor source development on the Reservation. The opportunity to achieve VOC emissions reductions that could improve ozone air quality close to the NAAQS during summer months would be lost. We may consider seasonal emissions mitigation measures in a future rulemaking if additional CAA nonattainment requirements are triggered.

Comment: Environmental organization commenters asserted that the EPA must ensure existing sources are in compliance immediately upon the effective date of the final rule, rather than allowing an 18-month period for affected sources to come into compliance. The commenters claimed that the EPA failed to provide adequate justification for why vendors need 18 months to provide equipment to owners and operators when the estimated number of affected existing sources needing to install retrofits is similar to the number that were cited as able to install retrofits in in areas of the Basin where the EPA has approved the UDEQ to implement the CAA. Commenters also asserted that the EPA should promulgate the FIP with a specific process of how decisions will be made to grant requested extensions of the 18-month compliance period.

Response: We acknowledge the commenters' requests urging the agency to finalize and fully implement the FIP in a shorter timeframe than was proposed. We disagree that existing sources should be required to have all required controls installed immediately upon the effective date of the final rule. The final FIP may require operators of an estimated 2,165 existing sources on Indian country lands within the U&O Reservation to retrofit existing equipment and install combustion devices, at an estimated capital cost of about $230 million. We determined it would not be practical for affected operators to acquire the necessary equipment from vendors and have it installed at that many existing sources in two months. The evaluation of anecdotal information from the UDEQ on the time it took a similar number of existing sources to come into compliance was not comparable to the FIP, as the UDEQ's approvals were spread out over time and that information was only used as a data point to help inform our belief that a certain period of time is appropriate to allow existing sources to come into compliance. We agree, however, given the urgency of the need to improve air quality in the Basin and the fact that owners and operators have been on notice that the rule might come into effect since the proposed rule was published in January 2020, the compliance period can reasonably be shortened to ensure meaningful VOC emissions reductions will be achieved in a timely manner. Therefore, we are finalizing a 12-month period for existing sources to come into compliance with the FIP. We have retained flexibility for operators to request extensions to the compliance deadline but agree with commenters that the regulatory language should specify the process the EPA would take to make decisions granting requested extensions of the compliance period and have included such language in the final rule.

B. Major Comments Concerning Regulatory Authority for Minor Source Streamlined Construction Authorization

Comment: Industry commenters asserted that, given the amendment of the National O&NG FIP to permanently extend the streamlined approach for approval of new and modified true minor oil and natural gas sources to the portions of the Indian country lands within the U&O Reservation that are part of the 2015 Uinta Basin Ozone Nonattainment Area was already permanently finalized at its current location in the Code of Federal Regulations (CFR), it is not necessary to remove the regulatory authority from that FIP and add it to the final U&O FIP. The same commenters also asserted that it is not appropriate to take comment on the National O&NG FIP amendment as part of this rulemaking. Environmental organization commenters asserted, on the other hand, that the EPA must analyze the air quality impacts of the National O&NG FIP amendment, claiming that the EPA failed to do so as part of that action. The commenters noted that the EPA has a mandate under the CAA's minor NSR provisions to ensure that implementation of the program assures that the NAAQS are achieved and, therefore, cannot authorize construction of new and modified sources in a nonattainment area unless it demonstrates protection of the NAAQS through a modeling analysis and a mechanism that tracks emissions consumed by new and modified sources against emissions that are reduced.

Response: We agree with commenters that it is not necessary to move the location of the authority for the already-effective amendments to the National O&NG FIP to the final U&O FIP. We disagree that the proposed U&O FIP provided a fresh opportunity to comment on the merits of the National O&NG FIP amendment and that the proposed U&O FIP should have analyzed the air quality impacts of extending the National O&NG FIP to the Indian country portions of the nonattainment area. That action was promulgated through a separate rulemaking process [113] and was not challenged within the judicial review period of that regulatory action and is thus today fully effective. At most, the proposal to include this authority in the U&O FIP would have shifted the location of already-existing authority within the CFR, which might have promoted easier compliance for affected oil and natural gas sources but would not have established any new requirements. In any event, we have decided not to finalize the proposed shift in the location of the authority to the U&O FIP, as we determined that the agency resources required to revise the National O&NG FIP through the rulemaking process would outweigh any streamlining advantage gained; thus, the authority will remain in the National O&NG FIP, as established in the May 24, 2019, final rule.

Further, we disagree with the assertion that only modeling can support a conclusion that substantial emissions reductions from this FIP could be relied on to support authorization to construct new and modified minor oil and natural gas sources under the National O&NG FIP. Unlike the NSR program for major sources in nonattainment areas, the minor NSR program does not require emissions offsets from existing sources in authorizing construction of new or modified minor sources in nonattainment areas, but rather requires the reviewing authority to demonstrate that new or modified minor sources in a nonattainment area would not cause or contribute to a NAAQS violation. The reviewing authority is not required to conduct modeling of minor source emissions to make such a demonstration. Rather, the rule provides the reviewing authority discretion to require modeling if it is concerned that new construction may cause or contribute to NAAQS violations. That discretion in demonstrating NAAQS protection was at work in the action to amend the National O&NG FIP, where we relied on existing source emissions reductions that we expect will be achieved from implementation of a U&O FIP. Based on our analysis of the current pace of new development under the National O&NG FIP, we expect that these reductions will far exceed the expected emissions from new construction. Our estimate for the expected magnitude of future development was based on a

[113] *See* 84 FR 21240 (May 14, 2019).

quantitative analysis of the rate of new and modified true minor source development and emissions increases on the Indian country lands within the Uintah & Ouray Reservation for each of the full calendar years since the effective date of the National O&NG FIP (2017–2019). We have updated that estimate for the final FIP to include 2020 and 2021 and we find that the pace of development has not noticeably changed, such that development of new and modified true minor oil and natural gas sources would need to occur at over 90 times the current pace of development to consume the annual headroom that full compliance with this FIP is expected to generate.[114] With this reevaluation, we continue to support the conclusion that the reductions achieved by this FIP will create more than enough headroom for the current or higher rates of development for years to come while first and foremost improving ozone air quality. We plan to periodically reevaluate our assumptions in the future based on changes in the pace of development and may take additional actions to protect air quality as necessary or appropriate.

C. Major Comments Concerning Rule Applicability

Comment: (VOC Emissions from Storage Vessels, Glycol Dehydrators and Pneumatic Pumps) Environmental organization commenters claimed that the proposed VOC emissions control requirements for storage vessels, glycol dehydrators and pneumatic pumps should be strengthened to place a priority on the option of routing emissions to a process to meet the emissions reduction requirement over the option of combusting those emissions. The commenters reference the EPA's FIP for the FBIR (FBIR FIP)[115] and NSPS OOOOa[116] as examples where the EPA has previously done this. The commenters also asserted that, to the extent that the EPA does permit gas combustion, it must only permit the use of VOC emissions control devices designed to reduce VOC emissions by 98 percent and require annual control efficiency performance testing for those devices.

Response: Regarding the comment that priority should be codified for the option of routing emissions to a process to meet the emissions reduction requirement over the option of combusting those emissions, we disagree. The commenters reference the EPA's FBIR FIP and NSPS OOOOa as examples of placing such priority, but that is a misinterpretation of the nuances of these regulations. The FBIR FIP allows lower-efficiency combustion of produced gas during well completion and through the first 90 days of production (using what is commonly known as pit flares). Within those first 90 days, the FBIR FIP requires all natural gas emissions from production operations and storage operations to be captured and routed through a closed-vent system to either a beneficial process or a high-efficiency combustion device, only allowing limited lower-efficiency combustion if routing to a process or high-efficiency combustion is temporarily infeasible (not to exceed 500 hours annually).[117] The FBIR thus places a priority on routing to a process or high-efficiency combustion over lower-efficiency combustion, but there is equal allowance for routing to a process and routing to a high-efficiency combustion device. NSPS OOOOa does prioritize routing of produced gas to a process over combustion for each well completion operation with hydraulic fracturing during the separation flowback stage. However, the same prioritization is not expressed for treatment of gases and vapors during ongoing production post-completion, which is only covered under NSPS OOOOa for well sites through the requirements for centrifugal compressors, reciprocating compressors, pneumatic controllers, pneumatic pumps, storage vessels, and the collection of fugitive emissions components at a well site's affected facilities.[118] Unlike the FBIR FIP and NSPS OOOOa, the final U&O FIP does not cover well completion operations. As the primary goal is to reduce existing source emissions to improve air quality in the Uinta Basin, the U&O FIP covers ongoing production operations at existing, new, and modified oil and natural gas sources that are not already subject to federal standards, including NSPS OOOO and OOOOa and NESHAP HH.

Regarding the comment that the EPA must only permit the use of VOC emissions control devices designed to reduce VOC emissions by 98 percent and require annual control efficiency performance testing for those devices, we disagree. As explained earlier,[119] we are reiterating our position in the proposed FIP that even devices that are designed to achieve at least 98 percent VOC control efficiency and able to demonstrate that control efficiency in controlled testing environments may not reliably achieve 98 percent control efficiency in the field on a continuous basis without stronger flare performance requirements than are currently in effect today in EPA's federal regulations that apply nationally. We believe that 95.0 percent continuous control efficiency is achievable when supplemented by the design, operational and parameter monitoring requirements in the final FIP. We expect that requirements for robust design of combustion devices, initial and subsequent performance testing (every 5 years) of enclosed combustors according to the procedures in NSPS OOOO and OOOOa (adopted by reference in the proposed FIP), and continuous monitoring of manufacturer-specified parameters that indicate optimal operation of a control device, including combustion temperature and a continuous pilot flame while emissions are routed to a device, are effective at indicating proper operation of a control device and more affordable and flexible than requiring annual performance testing of thousands of control devices or requiring exclusive use of particular devices. Requiring 95.0 percent continuous control efficiency also provides consistency with the EPA's federal regulations that apply nationally and consistency across all areas in the Uinta Basin, which operators are accustomed to complying with in the Uinta Basin already. Imposing more stringent control requirements on Indian country lands within the U& Reservation than are imposed in areas where the EPA has approved the UDEQ to implement the CAA may also unnecessarily create a competitive disadvantage to developing on the Indian country lands within the U&O Reservation, causing economic impacts to the Ute Indian Tribe and its citizens.

Comment: Industry asserted that the definition of ''fugitive emissions component'' and the repair timeline and inspection frequency should be consistent with those in NSPS OOOOa, to avoid divergent requirements for operators with sources subject to LDAR under the NSPS and sources subject to LDAR under the FIP. Environmental organization commenters asserted that the FIP applicability to the requirement to implement an LDAR program should not be limited to the minimum threshold for sources with total emissions from the collection of all

[114] The analysis is included in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709), Microsoft Excel spreadsheet titled, ''OGFIP Emissions_UO_2017–2021.xlsx.''

[115] *See* 40 CFR 49.4164(d).

[116] *See* 40 CFR 60.5375a(a)(1)(ii) and 60.5375a(a)(3).

[117] *See* 40 CFR 49.4164(b) through (e) and 49.4165(d)(2)(ii).

[118] *See* 40 CFR 60.5380a, 60.5385a, 60.5393a, 60.5395a, 60.5397a, 60.5410a, and 60.5411a.

[119] *See* Section IV.F.3 of this preamble.

storage vessel, glycol dehydrator and pneumatic pump emissions equal to or greater than 4 tpy VOC, because there is no inherent relationship between the quantity of vented emissions from tanks, dehydrators and pneumatic pumps (intended) and the source's fugitive emissions (unintended), and because the proposed LDAR requirements apply to components, such as compressors, that are categorically different than storage tanks, dehydrators and pneumatic pumps. These commenters asserted that all oil and natural gas sources should be required to implement an LDAR program, based on the results of recent studies indicating pneumatic devices often emit at higher rates than they are designed. The same commenters also asserted that the definition of ''fugitive emissions component'' should not exclude natural gas-driven pneumatic controllers and pumps that are designed to vent as part of normal operations.

Response: We agree with comments that the definition of ''fugitive emissions component'' should be consistent with that in NSPS OOOOa and we have revised the definition accordingly in the final FIP. We disagree with comments that the definition should not exclude pneumatic devices. The EPA has already codified that exclusion in NSPS OOOOa. Additionally, pneumatic devices are also subject to specific control requirements in the FIP, namely the requirements to control VOC emissions from pneumatic pumps at certain sources and to ensure that pneumatic controllers have a bleed rate of 6 scf/hr or less (*i.e.,* ''low-bleed''). We are aware of the studies regarding malfunctioning pneumatic controllers and refer the reader to the previous summaries of comments and our responses in this section regarding the applicability of pneumatic controllers. We agree with comments that the repair timeline should be consistent with those in NSPS OOOOa. We have not revised the LDAR inspection frequency of the proposed FIP to be entirely consistent with the frequency that is in NSPS OOOOa. The majority of the oil and natural gas sources that are subject to the FIP are existing sources that are not subject to NSPS OOOOa. The final semiannual inspection frequency for affected well sites is consistent with what is in the Utah Oil and Gas Rules, the CTG and NSPS OOOOa. For affected gathering and boosting compressor stations and natural gas processing plants, it is less frequent than the CTG and NSPS OOOOa in part.[120] The Utah Oil and Gas Rules do not cover gathering and boosting compressor stations or natural gas processing plants and the Utah Permit Requirements require varying inspection frequencies ranging from semiannual to monthly. There are far fewer existing gathering and boosting compressor stations, and even less existing natural gas processing plants, on the Indian country lands within the U&O Reservation than there are well sites. Because the CTG VOC guidelines and the NSPS OOOOa methane standards require at least quarterly inspections for existing, new, and modified compressor stations and natural gas processing plants, but the NSPS OOOOa VOC standards for new and modified compressor stations and natural gas processing plants and the Utah Permit Requirements for existing compressor stations and natural gas processing plants mandate LDAR inspection frequencies widely ranging from semi-annual to monthly, we determined that it is reasonable to simplify compliance with the final FIP by requiring a consistent semi-annual inspection frequency for all types of oil and natural gas sources. We note that the gathering and boosting compressor stations and natural gas processing plants subject to NSPS OOOOa would be required to comply with those fugitive emissions inspection requirements, rather than the FIP. We have, however, revised the procedural LDAR requirements of the proposed FIP to maximize consistency with the equivalent requirements of NSPS OOOOa, which addresses the concern that operators would be subject to divergent procedural requirements for sources subject to LDAR under the NSPS and sources subject to LDAR under the FIP.

In response to the comment criticizing our proposal to apply LDAR requirements to sources that are required to control facility-wide VOC emissions from the collection of all storage vessels, glycol dehydrators and pneumatic pumps (*i.e.,* emissions from those equipment are greater than or equal to 4 tpy), we do agree that there is not strong evidence of a direct inherent relationship between the quantity of vented emissions from the collection of all storage vessels, dehydrators and pneumatic pumps (intended) and a source's fugitive emissions (unintended). We also agree that the proposed LDAR requirements apply to components, such as compressors, that are categorically different than storage vessels, dehydrators and pneumatic pumps. But we disagree that these observations compel the conclusion that the FIP should apply LDAR requirements to all sources, for the reasons explained below. Applying LDAR requirements to all existing, new, and modified oil and natural gas sources would be significantly more stringent than the Utah Oil and Gas Rules given the total number of existing oil and natural gas sources on the Reservation (6,870), versus the number of sources we estimate will be required to implement LDAR under this final rule (3,100). An even broader LDAR applicability than what is being finalized today, which itself is already broader than that in the Utah Oil and Gas Rules, would create inconsistency across all areas of the Basin that may prompt operators to shift development and associated emissions to areas of the Basin where the EPA has approved the UDEQ to implement the CAA or to cease existing production on Indian country lands within the U&O Reservation, both of which could have economic disbenefits for the Ute Indian Tribe. We evaluated whether there was a more appropriate measure to limit applicability to a required LDAR program in the final FIP. We evaluated exempting ''low-production'' well sites, or those with total daily production less than or equal to 15 boe, similar to the CTG. We also evaluated applying LDAR requirements to all oil and natural gas sources that meet either criterion: (1) VOC emissions from the collection of all storage vessels, glycol dehydrators and pneumatic pumps that are greater than or equal to 4 tpy; or (2) well sites with production greater than 15 boe per day. Applying LDAR to all oil and natural gas sources was analyzed as part of regulatory Option 3. In the final FIP we are applying LDAR requirements to all oil and natural gas sources that meet either criterion: (1) VOC emissions from the collection of all storage vessels, glycol dehydrators and pneumatic pumps that are greater than or equal to 4 tpy; or (2) well sites with production greater than 15 boe per day. We determined this approach would address the comment that there is not strong evidence of a direct inherent relationship between the quantity of vented emissions from storage vessels, dehydrators and pneumatic pumps

[120] As discussed earlier in Section V.D. of this preamble, we acknowledge that NSPS OOOOa currently contains two different LDAR inspection standards for well sites and gathering and boosting compressor stations controlling methane emissions and those controlling VOC emissions and that the EPA has published a proposed national rule to reduce methane and other pollutants from existing, new, and modified sources in the oil and natural gas industry that proposes to align those standards to require semiannual LDAR inspections for all well sites (no exemption for low-production wells) and quarterly LDAR inspections for all compressor stations (*see* 86 FR 63110, Nov. 15, 2021).

(intended) and a source's fugitive emissions (unintended). This approach is a middle ground that provides some consistency with both the LDAR applicability of the Utah Oil and Gas Rules and that of the CTG for existing sources. Additionally, from an air quality protection perspective, it is reasonable to make a change from what was proposed that would maximize VOC emissions reduced without requiring all existing oil and natural gas sources to implement an LDAR program. We acknowledge some recent studies indicating that leaks have consistently been observed at certain well sites with less than 15 boe per day.[121] We also acknowledge that the EPA has published a proposed national rule to reduce methane and other pollutants from existing, new, and modified sources in the oil and natural gas industry that proposes to repeal amendments in the 2020 Technical Rule that exempted low-production well sites from monitoring fugitive emission.[122] We may revisit this final action in the future based on any final action we take under CAA section 111 with the Oil and Natural Gas Sector Climate Review rulemaking to address application of LDAR at sources covered by this FIP in a manner similar to the final national rule's provisions for sources that it covers. Also, if the Uinta Basin Ozone Nonattainment Area's Marginal classification is reclassified (''bumped up'') to a Moderate nonattainment classification, or if air quality concerns otherwise warrant, we may conclude that further rulemaking is necessary or appropriate.

Comment: Environmental organization commenters asserted that the proposed FIP requirement that all pneumatic controllers be continuous low-bleed controllers, consistent with NSPS OOOO and OOOOa, is insufficient, adding that while continuous low-bleed controllers are superior to high-bleed controllers, they are documented in recent studies to emit significant VOC emissions both from normal operations (*i.e.,* by design) and often due to equipment malfunctions. The commenters asserted that recent evidence indicates zero-emissions controllers (*e.g.,* electric valve, instrument air-actuated, and solar power valve actuated) are cost-effective, widely used, and environmentally necessary.

Response: We disagree that the EPA mandating zero-emissions controllers is necessary or required here and provided reasoning in the proposed FIP for requiring low-bleed pneumatic controllers rather than zero-emissions pneumatic controllers. The EPA believes that, within the context of this rulemaking and the specific purposes it is intended to accomplish, we do not have sufficient information to finalize such a requirement for the Indian country lands within the U&O Reservation at this time. Further, including such a requirement in the final FIP would not serve to further the EPA's goal of providing regulatory consistency at this time. In the interest of improving air quality by achieving emissions reductions as soon as possible and in a manner that promotes regulatory consistency across all areas in the Uinta Basin, we are finalizing the FIP with the requirement that pneumatic controllers be at least low-bleed. Although zero-bleed controllers are not specifically required, the regulatory text of the final U&O FIP does not prohibit operators from using zero-bleed controllers to comply with the rule, as it incorporates by reference the pneumatic controller requirements of NSPS OOOOa at 40 CFR 60.5390a, which specify at 40 CFR 60.5390a(c)(1) that ''Each pneumatic controller affected facility at a location other than at a natural gas processing plant must have a bleed rate *less than or equal* to 6 standard cubic feet per hour.'' (emphasis added). We acknowledge that the EPA's Oil and Gas Sector Climate Review Proposed Rule proposes to require pneumatic controllers to have zero emissions, subject to limited exceptions.[123] However, that proposed requirement is not yet final and the EPA did not include a similar requirement as part of the proposal for this rulemaking. We may revisit this final action in the future based on any final action we take under CAA section 111 with the Oil and Natural Gas Sector Climate Review rulemaking to address pneumatic controllers at sources covered by this FIP in a manner similar to the final national rule's provisions for sources that it covers. Also, if the Uinta Basin Ozone Nonattainment Area's Marginal classification is reclassified (''bumped up'') to a Moderate nonattainment classification, or if air quality concerns otherwise warrant, we may conclude that further rulemaking is necessary or appropriate.

Comment: Environmental organization commenters asserted that the proposed FIP should require capture and control of VOC emissions during truck loading and unloading. The commenters claimed that the EPA failed to take into account that truck loading and unloading is an activity that occurs repeatedly and provides an opportunity for emissions reductions and the EPA failed to provide calculations to support the cost-prohibitiveness of requiring such controls.

Response: We disagree. In developing the proposed rule, we found that the estimated annual share of VOC emissions from truck loading and unloading in the UBEI2014 was only 2 percent of the VOC emissions inventory and such a requirement would not be expected to contribute to meaningful VOC reductions compared to submerged fill and bottom loading requirements. The UBEI2017-Update indicates that truck loading and unloading represents an even smaller portion of the VOC emissions inventory at 1 percent. We did not receive new information during the public comment period on the cost of capture and control of emissions from truck loading and unloading to compel us to change the proposed requirement. Therefore, we are finalizing truck loading and unloading requirements as proposed. We may consider such a requirement in a future rulemaking if additional action is required to address air quality impacts from ozone pollution, or we may consider it as a creditable emissions reduction to offset permitting of a new or modified major source or demonstrating general conformity. We acknowledge that the EPA's Oil and Natural Gas Sector Climate Review Proposed Rule solicits comment on whether the EPA should propose to require capture and control

[121] A study by the Boulder County Health Department, ''Leak Inspection and Repair at Oil and Gas Well Sites

Boulder County Public Health Voluntary Inspection Program Results 2014–2018,'' tracked leaks at well pads in Boulder County over a five-year period using OGI. The program resulted in 1,022 inspections at 147 well pad sites across the county from 2014 through 2018. Cumulatively, gas leaks were detected at 86 percent [*i.e.,* 126/147] of inspected sites, with the percentage each year ranging from 38 percent to 49 percent. 64 percent of the sites with leaks experienced them in multiple calendar years. An earlier version of the study (2014–2016) was referenced via comments on the proposed NSPS OOOOa technical revisions, available in the docket for that rulemaking at *https://www.regulations.gov* (Docket ID No. EPA–HQ–OAR–2010–0483–0748). Since then, two additional study years through 2018 were added. The report is available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709). We conducted an analysis showing that of the average BOED per well ranged from 1.6 to 2.3 from 2014–2018, indicated in the November 18, 2019, email from Cindy Beeler, EPA, available in the docket for this rulemaking at *https://www.regulations.gov* (Docket ID No. EPA–R08–OAR–2015–0709); and Deighton, J. A., Townsend-Small, A., Sturmer, S. J., Hoschouer, J., & Heldman, L. (2020). Measurements show that marginal wells are a disproportionate source of methane relative to production. Journal of the Air & Waste Management Association, available at *https://www.tandfonline.com/doi/full/10.1080/10962247.2020.1808115,* accessed Mar. 14, 2022.

[122] *See* 86 FR 63110 (Nov. 15, 2021).

[123] *See* 86 FR 63110, Nov. 15, 2021.

of VOC and methane emissions from truck loading and unloading.[124] We may revisit this final action in the future based on any proposal and subsequent final action we take under CAA section 111 for the Oil and Natural Gas Sector to address truck loading and unloading at sources covered by this FIP in a manner similar to a final national rule's provisions for sources that it covers. Also, if the Uinta Basin Ozone Nonattainment Area's Marginal classification is reclassified (''bumped up'') to a Moderate nonattainment classification, or if air quality concerns otherwise warrant, we may conclude that further rulemaking is necessary or appropriate.

Comment: Several commenters claimed the EPA should regulate VOC emissions from additional equipment or activities as part of the final FIP, including oil and natural gas wastewater pond evaporation facilities, intermittent bleed pneumatic devices, well production associated gas and small two-stroked rich-burn engines. Commenters also asserted that the EPA should regulate sources of NO_X emissions as part of the final FIP, as it is an ozone precursor and some studies have indicated the NO_X reductions in the Uinta Basin may result in meaningful reductions in the formation of ozone. NO_X emissions sources that commenters asserted should be covered by the FIP include engines, turbines, boilers, heaters, flares and thermal incinerators.

Response: Regarding the comments that the FIP should cover additional VOC emissions sources, we are not finalizing emissions control requirements for any sources in addition to what was proposed. The primary reason is that we proposed to act on the sources as to which we had sufficient cost and emissions reduction information specific to the Uinta Basin and from which we expected that significant emissions reductions could be achieved in a manner that maximizes regulatory consistency across all areas in the Basin. We are finalizing this rule as applicable to those sources in order to achieve emissions reductions quickly and improve air quality and public health within the U&O Reservation as soon as possible. It may be possible in the future to achieve further reductions by regulating additional sources, and if we conclude that such further regulation is appropriate, we will propose action on it in a future U&O Reservation rulemaking in order to receive public comment. The EPA is actively participating in ongoing research to better understand emissions from all of the aforementioned VOC emissions sources in the Uinta Basin. We acknowledge that the EPA's Oil and Natural Gas Sector Climate Review Proposed Rule has presented new information and analysis that will likely be relevant for reducing emissions on the U&O Reservation and solicits additional information on evaluating and potentially covering at least some of these sources on a national basis.[125] Our assessment of new, potentially relevant information will continue in the context of the Climate Review Rule still being developed. If we finalize a national Climate Review Rule in the future, its requirements will apply directly to covered sources. As to sources not covered by a final national rule, we may find it necessary or appropriate to revisit this final action in the future and revise it through the rulemaking process (including public notice and comment) based on information evaluated in issuance of that final national rule. Also, if the Uinta Basin Ozone Nonattainment Area is reclassified to a Moderate nonattainment classification, or if air quality concerns otherwise warrant, we may find that further rulemaking is necessary or appropriate.

Regarding the comments that the FIP should cover sources of NO_X emissions, we maintain our conclusion from the proposed rule that most recent studies on winter ozone in the Uinta Basin indicate that ozone in the Basin is sensitive to changes in VOC emissions and that the effect of changes in NO_X emissions is less certain, and, therefore, VOC reductions will have the most cost-effective impact in reducing winter ozone formation in the Basin. We may consider focusing on NO_X emissions reduction in future rulemakings if additional action is required to address air quality impacts from ozone pollution and any control technology and cost information commenters provided may be useful in those cases. We may also consider future NO_X emissions reductions as creditable to offset permitting of a new or modified major NO_X emissions source or in demonstrating general conformity. We refer the reader to the Response to Comments document in the docket for this rulemaking for more details on our consideration comments related to regulating additional VOC emissions sources and regulating NO_X emissions sources.

Comment: Industry commenters asserted that the U&O FIP should only apply to Indian country lands within the Uinta Basin Ozone Nonattainment Area boundary, rather than all Indian country lands within the U&O Reservation, as proposed. Environmental organization commenters asserted that the term ''Uintah and Ouray Reservation'' must be defined in the regulatory text of the rule and should mean the lands ''within the exterior boundaries of the U&O Reservation.''

Response: We disagree with the comment that the FIP should only apply to Indian country lands within the Uinta Basin Ozone Nonattainment Area boundary. We are finalizing the FIP to impose the VOC emissions reduction requirements to all Indian country lands within the U&O Reservation for multiple reasons: (1) Implementing the requirements only to sources in the nonattainment area would be complex to implement, because it would present a second layer to already complex case-specific determinations of CAA jurisdiction and applicability to the FIP and would result in operators potentially needing to comply with different regulatory requirements within Indian country; and (2) Applying the FIP only to the Indian country portions of the nonattainment area would result in inconsistent requirements across all areas in the Uinta Basin, as the Utah Oil and Gas Rules apply to all oil and natural gas sources in areas of the Bain where the EPA has approved the UDEQ to implement the CAA, not just those in the nonattainment area. We agree with the comment that the term ''U&O Reservation'' was undefined in the regulatory text of the proposed rule and have added clarification to the final rule regulatory text in 40 CFR 49.4169 that ''U&O Reservation'' refers to the ''Uintah and Ouray Indian Reservation.'' We disagree that the rule text should state that it applies ''within the exterior boundaries of the U&O Reservation.'' The proposed rule stated that it applies to the ''Indian country lands within the U&O Reservation.'' There are non-Indian country lands within the exterior boundaries of the U&O Reservation. Therefore, we have added a definition of ''Indian country'' to 40 CFR 49.4171 that references the corresponding definition at 18 U.S.C. 1151.

D. Major Comments Concerning Monitoring and Testing Requirements

Comment: Industry commenters asserted that the proposed requirement to perform auditory/visual/olfactory (AVO) surveys while crude oil, condensate, intermediate hydrocarbon liquids and produced water storage vessels are being filled is impractical, due to the non-static nature of separators cycling and liquids transfer

[124] *See* 86 FR 63110, Nov. 15, 2021.

[125] *See* 86 FR 63110 (Nov. 15, 2021).

that could result in an operator being on location for a burdensome period of time to comply. The commenters also asserted that the proposed required monthly AVO inspections should not be finalized because they go beyond NSPS OOOOa and the UDEQ requirements and are duplicative of the proposed monthly inspections required in 40 CFR 49.4183(c) and (e) and the semi-annual monitoring of fugitive emissions components in 40 CFR 49.4179. The commenters asserted that the final FIP should provide more flexibility in determining compliance with the no detectable emissions limit for covers and closed-vent systems by allowing multiple options to perform inspections, including AVO and OGI.

Response: We agree with the commenters that the monitoring requirements in proposed 40 CFR 49.4183(c), (d) and (e) contained some redundancy and risk affected sources being subject to duplicative requirements. We have revised paragraphs (c) through (e) to merge paragraphs (c) and (d) (now in 40 CFR 49.4182 in the final FIP) for more consistency with NSPS OOOOa. We have also incorporated more streamlined language that is still consistent with that section, rather than incorporate by reference the cover and closed vent system inspection requirements from 40 CFR 60.5416a(c). Additionally, we agree with comments that, in addition to AVO inspections, consistent with NSPS OOOOa, the FIP should provide the option to conduct optical gas imaging inspections of covers and closed vent systems at the same frequency as required fugitive emissions inspections and have included a similar option.

Regarding the proposed requirement that monthly inspections must be performed while storage vessels are being filled, we acknowledge that storage vessel filling at certain well sites may occur less frequently than at other sites, due to the non-static nature of separator cycling and liquids transfer. We have removed the portion of the requirement that inspections must be performed while storage vessels are being filled. Because one cannot always hear or smell emissions from the collection of all storage vessels, we continue to hold the view that inspections conducted during filling events can be valuable for identifying storage vessel and closed vent system integrity defects, as filling events generate the largest flashing emissions. To maintain the effectiveness of visual inspections in identifying defects, in light of removal of the requirement that they be conducted during filling events, we have added language to 40 CFR 49.4182(c) that inspectors should note whether there are signs of oil releases around storage vessel thief hatches, seals and pressure relief valves (*i.e.,* staining on the storage vessel), which may indicate over-pressure events that have occurred when the storage vessel was being filled. We emphasize that final 40 CFR 49.4173(c)(1) requires that all flashing, working, standing and breathing losses from storage vessels must be routed through a closed-vent system. This includes flashing losses during filling events.

Comment: Industry commenters suggested that the FIP should include language consistent with the provisions of NSPS OOOOa for unsafe and difficult to monitor fugitive emissions components and delay of repair if repair or replacement is technically infeasible, would require a vent blowdown, compressor station shutdown, well shutdown or shut-in, or would be unsafe to repair during operation of the unit.

Response: We agree and have revised the language of the proposed FIP to include language more consistent with the difficult-to-monitor and unsafe-to-monitor provisions of the NSPS, including exceptions for the timelines to inspect and repair such fugitive emissions components and requirements that the fugitive emissions plan include the specialized timelines.

Comment: Environmental organization commenters asserted that, given the urgent need to reduce ozone pollution in the Uinta Basin and the high cost-effectiveness of LDAR, the FIP must require quarterly or monthly LDAR surveys instead of the proposed semi-annual surveys, and must require leaking equipment repair more quickly than 30 days after discovering the leak. While the proposed requirements are consistent with NSPS OOOOa, the commenters referenced that EPA either contemplated during proposal or had required such provisions in previous versions of NSPS OOOOa and that other oil and gas producing states impose such requirements.

Response: Regarding LDAR survey frequency, we direct the reader to our response to comments on LDAR applicability. We disagree with commenters suggesting the final FIP should contain stricter procedural LDAR requirements than are effective in NSPS OOOOa, including repair of leaking equipment more quickly than 30 days after discovering the leak. We determined that finalizing procedural LDAR requirements that are consistent with NSPS OOOOa (and by extension, UDEQ oil and gas rules) addresses the concern expressed by other commenters that affected operators would have to comply with different fugitive emissions monitoring programs than they are required to implement for sources in the same area that are subject to NSPS OOOOa or the UDEQ Oil and Gas Rules and will allow for more straightforward compliance throughout the Basin. Implementing LDAR requirements in the final FIP that are procedurally different than the requirements in NSPS OOOOa or the Utah Oil and Gas rules may also potentially create disincentives for development on the Reservation and of Tribally owned resources, leading to economic disadvantages for the Ute Indian Tribe and its members. While we appreciate the alternative cost information and comparison of state oil and gas LDAR requirements provided by commenters, we do not agree that the information provided is relevant to establishing requirements for monitoring in the Uinta Basin for the purposes and goals of this rulemaking. We determined that the LDAR procedural requirements will still result in meaningful VOC emissions reductions from LDAR on the Indian country lands within the U&O Reservation, while avoiding a complex regulatory scheme for entities that operate some sources subject to the FIP requirements and other sources subject to NSPS OOOOa or requirements in areas where the EPA has approved the UDEQ to implement the CAA.

E. Major Comments Concerning Recordkeeping and Reporting

Comment: Industry commenters suggested that the recordkeeping and reporting requirements should align with those in the UDEQ regulations, saying that the proposed FIP requirements were in many cases more detailed, prescriptive and stringent than those in UDEQ regulations and could result in discouraging oil and gas development on the U&O Reservation. Examples provided of discrepancies in recordkeeping requirements included that the UDEQ does not require annual compliance reports or that records be kept of all required monitoring of operations every time an operator is on site. The commenters referenced other examples where the UDEQ requires certain records that were not proposed in the U&O FIP. The commenters suggested recordkeeping and reporting requirements should be limited to those that help demonstrate compliance with the VOC emission reduction requirements, such as records of instances when closed-vent-systems conveying emissions to a control device bypass the device, records of observed instances when the combustor or flare is inoperable or not operating properly, as well as information on actual emissions. The commenters encouraged the EPA to increase the number of recordkeeping requirements in alignment with the UDEQ requirements in exchange for removing the annual compliance reporting requirement.

Response: We agree with commenters that required elements of recordkeeping and reporting in the final FIP should be limited to the most relevant information to assure compliance with the emissions control requirements of the FIP. We have revised the list of required records accordingly and streamlined the required annual report content to only include summaries of the records of the most relevant information to demonstrate compliance. We disagree with commenters that the U&O FIP should not require compliance reporting. Reporting at regular intervals is an important mechanism to ensure that regulations are enforceable as a practical matter. We recognize that the UDEQ regulations do not require annual compliance reporting and are not commenting on the efficacy of the UDEQ's regulations with this response. It is not reasonable for the EPA to rely only on records to assure compliance, particularly in an area with thousands of affected facilities, as we do not have the resource capacity to visit every facility to access them and it would be inefficient to use CAA section 114 authority on a case-by-case basis to obtain them. It is common for the EPA to require both recordkeeping and reporting in CAA regulations, using the broad authority of section 114, sufficient for practical enforceability of the requirements and so that the public has transparent access to records demonstrating compliance.

Comment: Commenters requested the proposed requirement to keep records of the inspector signature be removed from the recordkeeping and reporting requirements, because many operators have moved to digital recordkeeping systems and physical signatures are not feasible with those systems. Commenters instead requested that it would be sufficient to just require inspector IDs be maintained and reported.

Response: We agree that recordkeeping and reporting requirements should facilitate the increasing use of digital recordkeeping and have finalized regulatory text in 40 CFR 49.4184(a)(1)(v)(D) accordingly to require the inspector's name or identification number.

F. Major Comments Concerning Cost-Benefit Analysis

Comment: Industry commenters asserted that the cost benefit analysis completed by the EPA for the proposed FIP lacked transparency and relied on information collected over 5 years ago for the CTG, failing to check the accuracy of the cost information included for that action and disregarding information previously submitted for the proposed CTG specific to VOC emissions control and storage vessel retrofit costs. Commenters incorporated those comments by reference in their comments to the proposed U&O FIP. The commenters also claimed that the EPA did not account for all burdens and costs associated with compliance with the VOC emissions control requirements, particularly higher costs for retrofitting existing storage vessels with controls, monthly storage vessel inspections and associated recordkeeping and reporting costs.

Response: The EPA responded to the referenced comments submitted for the draft CTG and we are, therefore, not including new responses to those comments here.[126] We note that in response to those comments, the EPA did make small changes to the cost elements included in the cost analysis for existing storage vessels that did not result in any change to the EPA's recommended applicability threshold for storage vessels in the final CTG. We based costs for retrofitting existing storage vessels on those costs in the final CTG that included those minor revisions. The costs recognize that it is more expensive to retrofit existing storage vessels for emissions control than to install controlled equipment upon construction. We did not update any of those costs for the final FIP, as we did not receive any new cost information on retrofitting storage vessels during the comment period for the proposed FIP. We acknowledge that the EPA's Oil and Natural Gas Sector Climate Review Proposed Rule[127] uses updated costs and emissions reduction estimates, including for fugitive emissions monitoring, retrofitting of existing storage vessels, storage vessel monthly inspections, installing zero emissions pneumatic devices, and associated recordkeeping and reporting costs.[128] [129] In order to achieve emissions reductions quickly and improve air quality and public health within the U&O Reservation as soon as possible, we have not updated our costs and emissions reductions estimates for the final FIP using those proposed estimates. If we conclude that further regulation is necessary or appropriate in the future, we will propose action on it in a future U&O Reservation rulemaking in order to receive public comment and would analyze any such rulemaking using the best available costs and emissions reductions estimates at that time.

Comment: Industry commenters also incorporated by reference portions of the comments they submitted for the draft CTG in their comments on the proposed FIP with regard to LDAR costs being underestimated.

Response: Again, the EPA previously responded to the referenced comments in issuing the final CTG and, therefore, we are not including new responses to those comments here. While we based the costs of implementing an LDAR program at existing oil and natural gas sources for the proposed FIP on those equivalent costs used for the final CTG, since the proposed FIP was issued the EPA has issued final technical revisions to NSPS OOOOa that included changes to fugitive emissions monitoring costs and emissions reduction estimates.[130] We have updated our costs and emissions reductions estimates for the final U&O FIP, relying in part on the updated fugitive emissions monitoring costs and emissions reduction estimates

[126] *Responses to Public Comments on the Draft Control Techniques Guidelines for the Oil and Natural Gas Industry.* Final Document. October 2016. Available in *https://www.regulations.gov,* Document ID No.EPA–HQ–OAR–2015–0216–0235, accessed Mar. 14, 2022.The Response to Comments Document for the U&O FIP summarizes the comments and the EPA's responses to those comments on the proposed CTG, as they relate to various provisions of the proposed U&O FIP.

[127] *See* 86 FR 63110, Nov. 15, 2021.

[128] *Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review.* Nov. 14, 2021, available at *https://www.regulations.gov,* Document ID No. EPA–HQ–OAR–2021–0317–0173, accessed Mar. 14, 2022.

[129] *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emission Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review.* October 2021, available at *https://www.regulations.gov,* Document ID No. EPA–HQ–OAR–2021–0317–0166. In general, many of the cost factors used were taken from technical support documents for earlier rulemakings, such as the 2012 NSPS OOOO, the 2016 CTG and NSPS OOOOa, and the 2020 Technical Rule, and were only updated to reflect 2019$. Most of the cost and emission reduction factors that were reevaluated for the 2021 proposed rule evaluated alternative compliance options, rather than significantly updating costs for control measures. Cost factor changes were characterized as minor. For example, see Tables 12–8a and 12–8b.

[130] The **Federal Register** document for the rulemaking, known as the technical amendments to the 2016 NSPS (85 FR 57398, Sept. 15, 2020), is available at *https://www.regulations.gov,* Document ID No. EPA–HQ–OAR–2017–0483 2247, accessed Mar. 14, 2022.

used for the final NSPS OOOOa revisions. We also acknowledge that the EPA has published a proposed national rule to reduce methane and other pollutants from existing, new, and modified sources in the oil and natural gas industry [131] that uses further updated fugitive emissions monitoring costs and emissions reduction estimates. In order to achieve emissions reductions quickly and improve air quality and public health within the U&O Reservation as soon as possible, we have not updated our costs and emissions reductions estimate for the final FIP using those proposed estimates. If we conclude that further regulation is necessary or appropriate in the future, we will propose action on it in a future U&O Reservation rulemaking in order to receive public comment and would analyze any such rulemaking using the best available costs and emissions reductions estimates at that time.

Comment: Environmental organization commenters asserted several flaws in the EPA's cost-benefit analysis regarding the societal benefits that will result from the avoided methane emissions due to VOC emissions reductions under the FIP. The most prominent flaw the commenters noted is the use of an interim value for the social cost of methane (SC–CH_4) that arbitrarily accounts only for domestic benefits of reduced methane emissions, which diverted from previously long-established and scientifically supported factors recognizing that methane emissions reductions have global benefits. The commenters also noted that the EPA arbitrarily discounted future climate effects at a 7 percent discount rate in addition to a 3 percent discount rate, which is inconsistent with Circular A–4's requirements to distinguish social discount rates from rates based on private returns to capital; to make plausible assumptions; to adequately address uncertainty, especially over long-time horizons; and to rely on the best available economic data and literature.

Response: We acknowledge these comments and that EPA policies have changed since we developed and analyzed the benefits of the proposed U&O FIP. The SC–CH_4 estimates presented in the RIA for the final U&O FIP are the SC–CH_4 estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990* (IWG 2021) (hereafter, ''February 2021 TSD''). EPA has evaluated the SC–CH_4 estimates in the February 2021 TSD and has determined that these estimates are appropriate for use in estimating the social benefits of CH_4 emission reductions expected to result from this final rule.[132] These SC–CH_4 estimates are interim values developed for use in benefit-cost analyses until updated estimates of the impacts of climate change can be developed based on the best available science and economics. After considering the TSD, and the issues and studies discussed therein, EPA concludes that it agrees with the rationale for these estimates presented in the TSD and summarized below.

In particular, the IWG concluded that the SC–GHG estimates developed under E.O. 13783, and used in the RIA of the proposed rule, fail to reflect the full impact of GHG emissions in multiple ways. First, the IWG concluded that those estimates fail to capture many climate impacts that can directly and indirectly affect the welfare of U.S. citizens and residents. Examples of affected interests include direct effects on U.S. citizens and assets located abroad, international trade, U.S. military assets and interests abroad, and tourism, and spillover pathways such as economic and political destabilization and global migration that can lead to adverse impacts on U.S. national security, public health, and humanitarian concerns. Those impacts are better captured within global measures of the social cost of greenhouse gases.

In addition, assessing the benefits of U.S. GHG mitigation activities requires consideration of how those actions may affect mitigation activities by other countries, as those international mitigation actions will provide a benefit to U.S. citizens and residents by mitigating climate impacts that affect U.S. citizens and residents. A wide range of scientific and economic experts have emphasized the issue of reciprocity as support for considering global damages of GHG emissions. Using a global estimate of damages in U.S. analyses of regulatory actions allows the U.S. to continue to actively encourage other nations, including emerging major economies, to take significant steps to reduce emissions. The only way to achieve an efficient allocation of resources for emissions reduction on a global basis—and so benefit the U.S. and its citizens—is for all countries to base their policies on global estimates of damages.

Therefore, for purposes of the RIA for this final rule EPA centers attention on a global measure of SC–CH_4. This approach is the same as that taken in EPA regulatory analyses over 2009 through 2016, as well as in more recent regulatory analyses, including for the *Final Revised Cross-State Air Pollution Rule (CSAPR) Update for the 2008 Ozone NAAQS.*[133] The present value of net benefits is estimated as the difference in the present values of monetized benefits and costs calculated at the 3 percent percent discount rates. We do not discount future climate effects at a 7 percent discount rate.

Finally, a comprehensive estimate of climate damages to U.S. citizens and residents does not currently exist in the literature. Existing estimates are both incomplete and an underestimate of total damages that accrue to the citizens and residents of the U.S. because they do not fully capture the regional interactions and spillovers discussed above, nor do they include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature, as discussed further below. EPA, as a member of the IWG, will continue to review developments in the literature, including more robust methodologies for estimating the magnitude of the various direct and indirect damages to U.S. populations from climate impacts and reciprocal international mitigation activities, and explore ways to better inform the public of the full range of carbon impacts. While the IWG works to assess how best to incorporate the latest, peer reviewed science to develop an updated set of SC–GHG estimates, it recommended the interim estimates to be the most recent estimates developed by the IWG prior to the group being disbanded in 2017. The estimates rely on the same models and harmonized inputs and are calculated using a range of discount rates.

The response to comments document and the RIA for the final FIP provide more detailed discussion of the revised approach to estimating climate benefits from reducing methane as a benefit to reducing VOC.

[131] *See* 86 FR 63110, Nov. 15, 2021.

[132] We note that the monetized climate benefits presented in the RIA analysis and discussed here are not a part of the technical or legal basis of this action but are instead presented as part of the RIA analysis as required pursuant to Executive Orders, including E.O. 12866.

[133] Regulatory Impact Analysis for the Final Revised Cross-State Air Pollution Rule (CSAPR) Update for the 2008 Ozone NAAQS (EPA–452/R–21–002) (EPA Office of Air Quality Planning and Standards, Mar. 2021); available at *https://www.epa.gov/sites/default/files/2021-03/documents/revised_csapr_update_ria_final.pdf,* accessed July 30, 2021.

G. Other Comments of Significant Interest

Comments Concerning CAA Nonattainment Requirements

Comment: Environmental organization commenters asserted that CAA general conformity requirements apply to the EPA's issuance of this FIP, requiring a conformity analysis and a conformity determination.

Response: We disagree with these comments because under 40 CFR 93.153(a), the final action will not cause emissions increases above the threshold required to trigger conformity requirements (*i.e.,* no or de minimis emissions increase, see 40 CFR 93.153(c)(2)).

Comment: Industry commenters asserted that the EPA should preserve maximum flexibility for federal agencies to determine that their actions conform and take steps to streamline conformity demonstrations, such as including a statement that implementation of this FIP satisfies federal agency general conformity obligations or a clarification that all legal options for demonstrating conformity are available, including those listed at 40 CFR 93.153(f), 93.158(a)(1), 93.158(a)(5)(i)(A), 93.158(a)(5)(i)(B), and 40 CFR 93.158(a)(5)(iv). One commenter asserted that the EPA should clarify that the FIP is not a ''relevant'' implementation plan within the meaning of 40 CFR 93.158(a)(5)(iv) and that approval of the final FIP will not limit federal agencies' ability to rely on 40 CFR 93.158(a)(5)(iv) when demonstrating conformity.

Response: We disagree with these comments. We concluded that this FIP is exempt from the general conformity requirements in 40 CFR part 93, subpart B (see 40 CFR 93.153(c)(2)). As such, the FIP does not otherwise address general conformity or the responsibilities for the EPA or other federal agencies and federal agencies authorizing new emissions of NO_X and VOC that are from sources not covered by this FIP must conduct an applicability analysis, and must, if project emissions are above the applicable de minimis thresholds, make a conformity determination in accordance with 40 CFR part 93, subpart B. This review would also consider whether any activities are on a federal agency's Presumed to Conform List (PTC). (Individual federal agencies can develop their own list of activities that are presumed to conform (40 CFR 93.153(f) through (j)); to date, however, neither the Ute Indian Tribe, BLM, the EPA, nor the state of Utah have developed a PTC list for the Uinta Basin ozone nonattainment area.) Federal agencies needing to make a general conformity determination have an option available for the Indian country lands within the U&O Reservation: Demonstrate that the emissions from the federal action are fully offset within the nonattainment area through a revision to the applicable SIP (or TIP or FIP) or an equally enforceable measure that effects emissions reductions equal to or greater than the total of direct and indirect emissions from the action so that there is no net increase in emissions of that pollutant. 40 CFR 93.158(a)(5)(iii).

Comment: Environmental organization commenters asserted that the EPA is required to directly address the ways in which this FIP will have environmental justice implications and ensure that any final action puts into practice environmental justice principles. The commenters claimed that the EPA's environmental justice analysis for the proposed FIP was insufficient in focusing only on demographic information and concluding that the impacts would be positive for all populations and failing to address whether the FIP will sufficiently ameliorate the disproportionate public health impacts caused by high ozone levels in the region.

Response: We agree that environmental justice implications are required to be evaluated for any final U&O FIP action to improve the degraded air quality in the Basin—the primary purpose for this rulemaking. We expect this rulemaking to result in reductions of 23,000 tpy of VOC ozone precursor emissions on the Indian country lands within the U&O Reservation and subsequent reductions in ground level ozone formation in the Basin, which will reduce the adverse health impacts caused by ozone for any population residing in the Basin, on and off the Indian country lands within the U&O Reservation. We acknowledged in the proposal that this FIP is an important initial step in bringing the area back into attainment with the ozone NAAQS, but it is not expected to meet the requirements of an attainment FIP that we may prepare per the CAA if the area is bumped up to a Moderate nonattainment classification or higher in the future. We anticipate that the effects of this rulemaking will help demonstrate compliance in such future actions, while allowing more time to improve our understanding of emissions and our ability to model the full suite of actions necessary to achieve NAAQS attainment. We made improvements in the environmental justice analysis, contained in the RIA for this final rule, compared to that for the proposed FIP, including incorporating data on potential existing disproportionate impacts related to environmental burden, socio-economic vulnerability, and health. Evaluation of the additional data did not result in finalizing a substantially different rule than was proposed and follows existing EPA guidance [134] on environmental justice in rulemaking per the directives to federal agencies in the February 11, 1994, Presidential E.O. 12898 [135] and the January 20, 2021, Presidential E.O. 13985.[136]

VII. Impacts of This Final FIP

A. Air Emissions Impacts

The EPA projects that from 2023 to 2032, relative to the baseline, the final rule will result in about 23,000 tons of VOC emissions reductions, 59,000 tons of methane emissions reductions, and 3,100 tons of HAP emission reductions from affected oil and natural gas sources annually. We have estimated regulatory impacts beginning in 2023 as it is the first full year of implementation of this rule and have estimated impacts through 2032 to illustrate the accumulating effects of this rule over a longer period. The EPA did not estimate impacts after 2032 for reasons including limited information, as explained in the RIA.

B. Energy Impacts

There will likely be minimal change in emissions control energy requirements resulting from this rule. Additionally, this final action encourages the use of emission controls that recover hydrocarbon products that can be used on-site as fuel or reprocessed within the production process for sale. The energy impacts described in this section are those energy requirements associated with the operation of emission control devices.

[134] According to the EPA's June 2016 *Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,* page 66 and Section 2.1, the term ''disproportionate impacts'' refers to differences in impacts or risks that are extensive enough that they may merit Agency action. The determination of whether there is a disproportionate impact that may merit Agency action is a policy judgment informed by analysis of any discernable differences in anticipated impacts from the rulemaking on population groups of concern compared to all other population groups.

[135] E.O. 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations,* Feb. 11, 1994.

[136] EPA expressed a commitment to conducting environmental justice analysis for rulemakings based on a framework described in the final revisions to the Cross-State Air Pollution Rule (86 FR 23054, 23162, Apr. 30, 2021). And E.O. 13895, *Advancing Racial Equity and Support for Underserved Communities Through the Federal Government,* Jan. 20, 2021.

Potential impacts on the national energy economy of the rule are discussed in the economic impacts section.

C. Compliance Costs

The EPA estimates the total capital cost of the final FIP to be $280 million for affected sources. We looked at the effect of recovered methane as a cost saving measure. The value of recovered methane amounted to $2.1 million per year. The net PV of the regulatory compliance costs associated with this final rule over the 2023 to 2032 period when accounting for additional revenue from product recovery was estimated to be $560 million (in 2016 dollars) using a 7 percent discount rate and $610 million using a 3 percent discount rate. The net EAV of these costs when accounting for additional revenue from product recovery is estimated to be $81 million per year using a 7 percent discount rate and $72 million using a 3 percent discount rate.

D. Economic and Employment Impacts

Executive Order 13563 directs Federal agencies to consider the effect of regulation on job creation and employment. According to the Executive order, ''our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science.'' (Executive Order 13563, 2011). While a standalone analysis of employment impacts is not included in a standard benefit-cost analysis, such an analysis is of concern in the current economic climate given continued interest in the employment impact of regulations such as this final rule.

With respect to energy markets, the EPA has concluded that, while this action may affect the supply, distribution or use of energy, it is not likely to have significant energy market effects. For small entities, we conducted a screening analysis. Based on the results of this screening analysis, which is presented in the RIA for the final FIP, the EPA concluded that that the rule will not have a Significant Impact on a Substantial Number of Small Entities (SISNOSE). For employment impacts, we did not perform a quantitative analysis on all categories of employment changes as a result of the rule. This rule is expected to result in little change in oil and natural gas exploration and production and is not expected to result in significant changes to employment dedicated to these tasks. The EPA did, however, in its cost analysis for the rule, estimate changes in labor due to compliance activities. As presented in the RIA for this action, the EPA projected there will be increases in the labor required for compliance-related activities associated with this final rule. As the rule imposes VOC emission control requirements that are consistent with federal standards for the oil and natural gas industry that apply nation-wide or rules for similar sources that apply in areas of the Basin where the EPA has approved the UDEQ to implement the CAA, we expect that many operators of affected oil and natural gas sources may already have sufficient systems established for complying with the federal standards for other sources they operate in the Basin, and therefore labor impacts may be overstated in our estimates.

E. Benefits

The EPA expects climate and health benefits due to the VOC emissions reductions projected under this final rule, as well as climate benefits from methane emissions reductions. Climate benefits from reducing emissions of CH_4 can be estimated and monetized using interim estimates of the social cost of methane (SC–CH_4). The SC–CH_4 estimates used here are the SC–CH_4 estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990* (IWG 2021) (hereafter, ''February 2021 TSD''). EPA has evaluated the SC–CH_4 estimates in the February 2021 TSD and has determined that these estimates are appropriate for use in estimating the social benefits of CH_4 emission reductions expected to result from this final rule. These SC–CH_4 estimates are interim values developed for use in benefit-cost analyses until updated estimates of the impacts of climate change can be developed based on the best available science and economics. EPA and other agencies intend to undertake a fuller update of the SC–GHG estimates that takes into consideration the advice of the National Academies and other recent scientific literature.

We note that the methodology underlying the SC–CH4 estimates used in this RIA been subject to public comment in the context of dozens of proposed rulemakings as well as in a dedicated public comment period in 2013. Further, the monetized climate benefits presented in this analysis are not a part of the technical or legal basis of the proposed action for which the RIA was prepared. Rather, the monetized benefits associated with projected reductions in greenhouse gas emissions that may result from the final rule are presented solely for purposes of compliance with E.O. 12866 and to present the public with information regarding the full scope of potential benefits of the final rule. We note that there is an ongoing interagency process to update the SC–GHG estimates, including the SC–CH4 estimates used in this analysis, and there will be further opportunity to provide public input on the SC–GHG methodology through that process.[137] The RIA for the final FIP provides a more detailed discussion of the approach to estimating climate benefits from reducing methane as a benefit to reducing VOC.

The EPA estimated the PV of monetized climate benefits over the 2023 to 2032 period to be $1 billion using a 3 percent discount rate and estimated the PV of monetized net benefits to be $390 million using a 3 percent discount rate and $440 million using a 7 percent discount rate for costs and a 3 percent discount rate for benefits. We estimate the EAV of monetized climate benefits over the 2023 to 2032 period to be $120 million using a 3 percent discount rate. We estimated the EAV of net benefits to be $48 million using a 3 percent discount rate for both benefits and costs. We estimated the EAV of net benefits to be $39 million using a 3 percent discount rate for benefits and a 7 percent discount rate for costs.[138] These values do not account for health effects of ozone exposure from the decrease in methane emissions. Under the final rule, the EPA expects that VOC emissions reductions will improve air quality and are likely to result in health and welfare benefits associated with reduced exposure to ozone, $PM_{2.5}$, and HAP, but we did not quantify these effects at this time due to the data limitations described below. This omission should not imply that these benefits may not exist; rather, it reflects

[137] For example, EPA, on behalf of the IWG, published a **Federal Register** document on January 25, 2022, to solicit public nominations of scientific experts for the upcoming peer review the forthcoming update. *See https://www.federalregister.gov/documents/2022/01/25/2022-01387/request-for-nominations-of-experts-for-the-review-of-technical-support-document-for-the-social-cost.* EPA has a web page where additional information regarding the peer review process will be posted as it becomes available: *https://www.epa.gov/environmental-economics/scghg-tsd-peer-review.* There will be a separate **Federal Register** document for the public comment period on the forthcoming SC–GHG technical support document once it is released.

[138] As explained in the RIA, For the presentational purposes, we discuss the benefits associated with the average SC-CH_4 at a 3 percent discount rate, but the Agency does not have a single central SC-CH_4 point estimate. The EAV of benefits at a 3 percent discount rate is used to estimate the net benefits at a 7 percent discount rate for costs.

the inherent difficulties in accurately modeling the direct and indirect impacts of the projected VOC emissions reductions for the oil and natural gas industry in the Uinta Basin. To the extent that the EPA were to quantify these ozone and PM impacts, it would estimate the number and value of avoided premature deaths and illnesses using an approach detailed in the Particulate Matter NAAQS and Ozone NAAQS RIAs.[139] This approach relies on full-form air quality modeling for the oil and natural gas source category that would be suitable for use in regulatory analysis in the context of NSPS, including ways to address the uncertainties regarding the scope and magnitude of VOC emissions.

When quantifying the incidence and economic value of human health impacts of air quality changes, the Agency sometimes relies upon alternative approaches to using full-form air quality modeling, called reduced-form techniques, often reported as ''benefit-per-ton'' values that relate air pollution impacts to changes in air pollutant precursor emissions.[140] Several studies have discussed the air quality and health impacts from the oil and natural gas industry.[141] The Agency believes more work needs to be done to vet the analysis and methodologies for all potential approaches to valuing the health effects of VOC emissions changes in areas experiencing elevated winter ozone before they are used in regulatory analysis, but is committed to continuing this work. Recently, the EPA systematically compared the changes in benefits, and concentrations where available, from its benefit-per-ton technique and other reduced-form techniques to the changes in benefits and concentrations derived from full-form photochemical model representation of a few different specific emissions scenarios.[142] The Agency's goal was to create a methodology by which investigators could better understand the suitability of alternative reduced-form air quality modeling techniques for estimating the health impacts of criteria pollutant emissions changes in the EPA's benefit-cost analysis, including the extent to which reduced form models may over-or-under-estimate benefits (compared to full-scale modeling) under different scenarios and air quality concentrations. The EPA Science Advisory Board (SAB) recently convened a panel to review this report.[143] In particular, the SAB will assess the techniques the Agency used to appraise these tools; the Agency's approach for depicting the results of reduced-form tools; and steps the Agency might take for improving the reliability of reduced-form techniques for use in future RIAs.

VIII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is an economically significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, ''Regulatory Impact Analysis of the Final Federal Implementation Plan for Managing Emissions from Oil and Natural Gas Sources on Indian Country Lands Within the Uintah and Ouray Indian Reservation in Utah'' (Ref. EPA–908/Z–16–001), is available in the docket, and is summarized in *Section VII. Impacts of this Final FIP.*

B. Paperwork Reduction Act (PRA)

The information collection activities in this rule will be submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2539.02. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

This final action imposes a new information collection burden under the PRA. The ICR covers information collection necessary to meet the requirements in this U&O FIP. In general, owners or operators are required to maintain records of required monitoring and other rule compliance. This U&O FIP also requires annual reports containing information for each oil and natural gas source, including a summary of certain required records during the reporting period, and a summary of certain instances where operation was not performed in compliance with the requirements of this U&O FIP during the reporting period. Additionally, a summary emissions inventory is required for each source covered under this rulemaking once every three years. These reports and records are essential in determining compliance and are required of all sources subject to this U&O FIP. The information collected will be used by the EPA or the Ute Indian Tribe to determine the compliance status of sources subject to the rule.

The EPA received one comment letter specifically on the ICR for the proposed U&O FIP, as well as several other comments related to the monitoring, recordkeeping, and reporting in the proposed rule. The EPA responded to these comments, as summarized in Sections VI.E and F. of this preamble and in the response to comments document in the docket for this rulemaking.[144]

Respondents/affected entities: The potential respondents are owners or operators of existing, new, and modified oil and natural gas sources on Indian country lands within the U&O Reservation.

Respondent's obligation to respond: Mandatory. The EPA is charged under sections 301(a) and 301(d)(4) of the CAA to promulgate regulations as necessary

[139] U.S. EPA. December 2012. ''Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter.'' EPA–452/R–12–005. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

U.S. EPA. September 2015. ''Regulatory Impact Analysis of the Final Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone.'' EPA–452/R–15–007. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

[140] U.S. EPA. 2018. ''Technical Support Document: Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from 17 Sectors.'' February, available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

[141] Fann, N., K.R. Baker, E.A.W. Chan, A. Eyth, A. Macpherson, E. Miller, and J. Snyder. 2018. ''Assessing Human Health $PM_{2.5}$ and Ozone Impacts from U.S. Oil and Natural Gas Sector Emissions in 2025.'' Environmental Science and Technology 52(15):8095–8103.

Litovitz, A., A. Curtright, S. Abramzon, N. Burger, and C. Samaras. 2013. ''Estimation of Regional Air-Quality Damages from Marcellus Shale Natural Gas Extraction in Pennsylvania.'' Environmental Research Letters 8(1), 014017.

Loomis, J. and M. Haefele. 2017. ''Quantifying Market and Non-market Benefits and Costs of Hydraulic Fracturing in the United States: A Summary of the Literature.'' Ecological Economics 138:160–167.

[142] This analysis compared the benefits estimated using full-form photochemical air quality modeling simulations (CMAQ and CAMx) against four reduced-form tools: InMAP, AP2/3 EASIUR, and the EPA's benefit-per-ton.

[143] 85 FR 23823 (Apr. 29, 2020).

[144] *Response to Public Comments, Proposed Federal Implementation Plan: Managing Emissions from Oil and Natural Gas Sources on Indian Country Lands within the Uintah and Ouray Indian Reservation in Utah, April 2022,* available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

to protect tribal air resources. Promulgating this U&O FIP will address winter ozone air quality concentrations that exceed the NAAQS, and given the 2015 ozone NAAQS marginal nonattainment designation, when combined with the National O&NG FIP amendments, would provide justification to allow continued streamlined construction authorization of new or modified true minor oil and natural gas sources, all in a manner that seeks to provide regulatory consistency between state and federal requirements with regard to controlling VOC emissions from existing, new, and modified oil and natural gas operations on the Indian country lands within the U&O Reservation. There is no other federal rule, including the recently finalized NSPS and NESHAP for the Oil and Natural Gas Sector (NSPS OOOO, NSPS OOOOa, and NESHAP HH), that establishes air pollution control regulations for the particular oil and natural gas operations that exist on the Indian country lands within the U&O Reservation that are appropriate to address the issues identified for this area. This is in contrast to oil and natural gas operations in areas where the EPA has approved the UDEQ to implement the CAA, which are governed by the UDEQ regulations and Utah Division of Oil, Gas, and Mining regulations. Consistent with the regulatory structure that exists in those areas, this U&O FIP has requirements for VOC emissions control and reductions, monitoring, recordkeeping, and reporting.

In addition, section 114(a) states that the Administrator may require any owner or operator subject to any requirement of this Act to:

- Establish and maintain such records;
- Make such reports;
- Install, use, and maintain such monitoring equipment, and use such audit procedures, or methods;
- Sample such emissions (in accordance with such procedures or methods, at such locations, at such intervals, during such periods, and in such manner as the Administrator shall prescribe);
- Keep records on control equipment parameters, production variables or other indirect data when direct monitoring of emissions is impractical;
- Submit compliance certifications in accordance with section 114(a)(3); and
- Provide such other information as the Administrator may reasonably require.

Estimated number of respondents: We estimate that an average of 6,870 oil and natural gas sources will be subject to one or more requirements in this U&O FIP over the next three years (including the requirement to report triennial emissions inventories as one requirement).

Frequency of response: Annual reports are required. Respondents must monitor all specified criteria at each affected source and maintain these records for five years.

Total estimated burden: 154,630 hours per year (3-year average), for all operators subject to this U&O FIP.

Total estimated cost: $26.2 million per year (3-year average); includes labor cost of $9.6 million, annualized capital cost of $10.4 million, and $6.1 million in operation and maintenance costs for all of the operators that would subject to this U&O FIP.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of this action are owners/operators of oil and natural gas sources on the Indian country lands within the U&O Reservation. They were identified through a screening analysis of existing oil and natural gas sources and emissions submitted by owners/operators on the Indian country lands within the U&O Reservation under UBEI2017–Update. The Agency has determined that only two out of 14 total small entities, or 14 percent, may experience an annualized cost impact of 1 percent to 3 percent of annual revenues, and thus may potentially incur significant economic impact. It was determined that the other 12 small entities would incur annualized costs less than 1 percent of annual sales, and therefore, are not expected to incur significant economic impacts from this rule. Details of this analysis are presented in the RIA and can be viewed in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

D. Unfunded Mandates Reform Act (UMRA)

This final action does not contain an unfunded mandate of $100 million of more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any state, local or tribal governments or the private sector.

1. Statutory Authority

The legal authority for this rule stems from sections 301(a) and 301(d)(4) of the CAA and 40 CFR 49.11(a). See section III.B of this preamble for more information.

2. Costs and Benefits

As discussed in *Section VII. Impacts of this Final FIP,* the estimated equivalent annualized costs of this rule in 2023, accounting for additional revenue from recovered natural gas, are $81 million in 2016 dollars using a 7 percent discount rate and $72 million in 2016 dollars using a 3 percent discount rate.[145] EPA estimates that the rule will lead to equivalent annual monetized benefits of about $120 million using a 3 percent discount rate. The quantified equivalent annualized net benefits of the regulation (the difference between the equivalent annualized monetized benefits and net equivalent annualized compliance costs) are estimated to be $39 million in 2016 dollars using a 7 percent discount rate and $48 million using a 3 percent discount rate.[146] More in-depth information on costs and benefits of the final regulation can be found in the RIA, including certain climate benefits and other benefits that were not quantified or monetized.[147]

3. Effects on National Economy

The EPA estimated the labor impacts due to compliance with the final rule for affected entities within the oil and natural gas industry, including the installation, operation, and maintenance of control equipment and control activities, as well as the labor associated

[145] The recordkeeping and reporting costs calculated for the ICR analysis, discussed earlier, are imbedded in the total annualized engineering costs included here.

[146] Benefits (methane reductions) were only calculated at a 3 percent discount rate, as that is the only rate that both cost and benefit analyses have in common. Therefore, the net benefits for the 7 percent discount rate were compared to benefits at a 3 percent discount rate to calculate the annualized net benefits of the final rule. The RIA in the docket for this rulemaking discusses this calculation in detail.

[147] The RIA includes a more detailed discussion of the potential costs and benefits associated with this rule. It can be viewed in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

with new reporting and recordkeeping requirements. We did not estimate any potential changes in labor outside of the affected industry, and due to data and methodology limitations we did not estimate net employment impacts for the affected industry, apart from the partial estimate of the labor requirements related to control strategies. The labor requirements analysis used a bottom-up engineering-based methodology to estimate employment impacts. The engineering cost analysis of the RIA includes estimates of the labor requirement costs associated with implementing the regulations. Each of these labor changes may be required as part of an initial effort to comply with the new regulation.

4. Regulatory Alternatives

Alternate regulatory options examined in the RIA include a low-impact option (Option 1) and a high-impact option (Option 3). Option 1 would not include control of emissions from glycol dehydrators. This is in contrast to preferred Option 2, which requires control of emissions from glycol dehydrators where the source-wide VOC emissions from the collection of all storage vessels, glycol dehydrators and pneumatic pumps is equal to or greater than 4 tpy per 40 CFR 49.4173 through 49.4177. The EPA could have considered a range of even less stringent regulatory options than Option 1 to evaluate and propose, including an option that would not require retrofit of existing storage vessels with controls or require controls less broadly. Retrofitting existing storage vessels with controls is one of the higher costs evaluated in this rulemaking. Such an option, however, would lead to even greater disparity with the requirements for similar sources in in areas of the Basin where the EPA has approved the UDEQ to implement the CAA than Option 1. Option 3 (high impact) would require implementation of an LDAR program at all existing oil and natural gas sources, regardless of daily production, or storage vessel, dehydrator, and pneumatic pump annual VOC emissions. We sought comment on the proposed FIP for whether it was appropriate to consider less or more stringent regulatory options, for example, an option that does not include retrofitting existing storage vessels for controls. We acknowledged that if comments supported finalizing less or more stringent regulatory options as viable and if the agency decided to adopt an option that was not offered in the proposal, the EPA may be required to hold an additional public comment period on this rulemaking. We did receive comments asserting both that less stringent and more stringent options were appropriate for this rulemaking. We summarized our responses to comments related to the regulatory options evaluated in the response to comments document in the docket for this rulemaking.[148]

The EPA estimates the equivalent annualized costs of the preferred option in 2023 in 2016 dollars using a 7 percent discount rate when accounting for additional revenue from product recovery are $81 million ($3,500 per ton of VOC reduced). When using a 3 percent discount rate, the estimates of total equivalent annualized costs of the final FIP when accounting for additional revenue from product recovery are $72 million when accounting for additional revenue from product recovery ($3,200 per ton of VOC reduced).

The equivalent annualized costs of the less stringent option (Option 1) when accounting for additional revenue from product recovery would be $77 million in 2023 in 2016 dollars using a 7 percent discount rate, resulting in a cost of control of $4,100 per ton of the estimated 19,000 tons of VOC reduced, and $69 million in 2023 using a 3 percent discount rate, resulting in a cost of control of $3,600 per ton of VOC reduced. Option 1 was analyzed to reduce burden on small entities, while still achieving meaningful VOC emissions reductions. Although this option would cost less overall than preferred Option 2, it would achieve less benefits in the form of VOC emissions reductions (19,000 tons versus 23,000 tons for final Option 2), as emissions from glycol dehydrators would not be controlled and a smaller number of oil and natural gas sources would be required to control storage vessels and pneumatic pumps, because a larger amount of VOC emissions would be required from the collection of all storage vessels and pneumatic pumps at sources that also have glycol dehydrators in order to trigger the control applicability threshold than under Option 2.[149] Additionally, by not controlling glycol dehydrator emissions in Option 1, there would also be significantly less benefits from the associated reductions in HAP emissions that are more reactive in forming ozone than the lighter-end VOC emissions resulting from storage vessels, pneumatic pumps and fugitive emissions. Implementation of Option 1 would also result in regulatory requirements that are inconsistent with the requirements for equivalent sources in areas of the Basin where the EPA has approved the UDEQ to implement the CAA, thus not meeting our goal of regulatory consistency across the Uinta Basin.

The equivalent annualized costs of the most stringent option (Option 3) when accounting for additional revenue from product recovery would be $88 million in 2023 in 2016 dollars using a 7 percent discount rate, resulting in a cost of control of $3,500 per ton of the estimated 25,000 tons of VOC reduced, and $79 million in 2023 using a 3 percent discount rate, resulting in a cost of control of $3,100 per ton of VOC reduced. Option 3 was analyzed to achieve a greater level of VOC emissions reductions. Although this option would achieve about 3,000 more tons of VOC emissions reductions than preferred Option 2 (25,000 tons versus 23,000 tons for final Option 2), it would also result in increased costs (though the cost of control per ton of VOC reduced would be about the same as Option 2). Additionally, Option 3 would result in regulatory requirements that are inconsistent with the requirements for equivalent sources in areas of the Basin where the EPA has approved the UDEQ to implement the CAA, thus not meeting our goal of regulatory consistency across the Uinta Basin.

For a more in-depth analysis of these options, see the RIA for this final U&O FIP.

E. Executive Order 13132: Federalism

This final action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This final action has tribal implications, because it establishes rules affecting a substantial number of industrial operations in Indian country within the U&O Reservation. The emissions improvement measures required by this rule will benefit the health and welfare of members of the Tribe. In addition, some of these

[148] *Response to Public Comments, Proposed Federal Implementation Plan: Managing Emissions from Oil and Natural Gas Sources on Indian Country Lands within the Uintah and Ouray Indian Reservation in Utah, March 2022,* available in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

[149] Under Option 1, the EPA would determine the 4 tpy threshold triggering control with source-wide potential VOC emissions from the collection of all storage vessels and pneumatic pumps only.

operations provide revenue to the Ute Indian Tribe, directly or indirectly. For example, the Tribe benefits from royalties paid by companies developing oil and natural gas resources on the Indian country lands within the U&O Reservation, which are administered by the U.S. Bureau of Indian Affairs. However, this rule will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law.

The EPA consulted with tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing this regulation to permit them to have meaningful and timely input on its development. A summary of that consultation and other communications with the Ute Indian Tribe follows. The EPA has conducted outreach on this final rule consistent with the *EPA Policy on Consultation and Coordination with Indian Tribes* (May 4, 2011) via ongoing monthly meetings with tribal environmental professionals [150] before and during the development of this final action, and further as follows: (1) via formal Tribal consultation and informal informational meetings with the Ute Indian Tribe Business Committee regarding options that the EPA could consider to address the Uinta Basin air quality concerns; (2) via stakeholder meetings where the Tribe was included and participated in emissions contributions discussions specific to the EPA's strategy for addressing the Uinta Basin air quality concerns; and (3) via ongoing stakeholder working group meetings convened by the Ute Indian Tribe Business Committee where the EPA participated in discussions with the Tribe and industrial operators on strategies to reduce existing ozone-related emissions and provide a streamlined construction authorization mechanism for new and modified minor oil and natural gas sources given the recent nonattainment designation for the 2015 ozone NAAQS.

The EPA held consultations with elected officials of the Ute Indian Tribe Business Committee on the following dates: July 22, 2015; December 17, 2016; November 13, 2017; March 22, 2018, August 17, 2018; November 14, 2018; February 28, 2019; April 2, 2019; February 5, 2020; and August 2, 2022. The EPA has also participated in tribally convened stakeholder meetings on March 22, 2017, and June 1–2, 2017, as well as many informal informational meetings with tribal elected officials and air quality staff.[151]

During the consultations and other discussions on this U&O FIP, the Tribe expressed concerns regarding their economic needs to develop and generate revenue from Tribal oil and natural gas resources; to consider air quality effects on the health, safety, and welfare concerns of their tribal membership living within the exterior boundaries of the U&O Reservation and the Uinta Basin; and to reconcile regulatory requirements for an even economic and regulatory playing field. We addressed questions the Tribe had regarding the controls being considered, the ability for owners or operators to take credit for the controls for purposes such as permitting and NAAQS attainment, the estimated costs of proposed controls, the characterization of Indian country, and the breadth of oil and natural gas source category types proposed to be regulated. The Ute-Tribe-convened stakeholder meetings involved discussions on appropriate ways to expedite nonattainment permitting for new and modified minor oil and natural gas sources on the Indian country lands within the U&O Reservation. Ute Indian Tribe and industry participants recognized that existing source emissions reductions would likely be necessary in order for the EPA to demonstrate that construction authorization for new and modified sources would not cause or contribute to NAAQS violations in the nonattainment area.

Enacting a FIP for Indian country lands within the U&O Reservation is directly responsive to the Ute Indian Tribe's air quality concerns in that we are implementing our CAA authority to protect air quality on and surrounding Indian country lands within the U&O Reservation in a manner that provides regulatory consistency with respect to requirements for oil and natural gas sources in areas of the Basin where the EPA has approved the UDEQ to implement the CAA. We are committed to supporting tribes' right to self-governance and to protecting their inherent sovereignty. Throughout development of this final action, we continued to provide outreach to tribal environmental professionals and continued consultation with tribal leadership.

As required by section 7(a), the EPA's Tribal Consultation Official has certified that the requirements of the executive order have been met in a meaningful and timely manner. A copy of the certification is included in the docket for this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This action is subject to Executive Order 13045 because it is an economically significant regulatory action as defined by Executive Order 12866 and the EPA has concluded that the environmental health or safety risk addressed by this final action has a disproportionate effect on children. Accordingly, we have evaluated the environmental health or safety effects of exposure to elevated ozone concentrations on children. This action's health and risk assessments are contained in the Impacts of this Final FIP and Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations sections in this preamble (sections VII. and VIII.K., respectively), with more detailed information contained in the RIA for this rulemaking.[152] This final U&O FIP should have a positive effect on the health of the residents of the Indian country lands within the U&O Reservation, including children, as it is expected to result in a reduction in ambient ozone concentrations, which disproportionately impact children, elderly, and those with respiratory ailments.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'', because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The basis for these determinations follows.

The EPA prepared an analysis of the potential costs and benefits associated with this action, which is included in the RIA,[153] and is summarized in *Section VII. Impacts of this Final FIP.* Based on this analysis, we have concluded that, while this action may have some effects on the supply, distribution, or use of energy, it is not likely to have significant adverse energy

[150] These monthly meetings are general in nature, dealing with many air-related topics, and are not specific to this proposed U&O FIP.

[151] The records of communication for all formal consultations and other discussions with the Ute Indian Tribe are included in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

[152] The RIA includes more detailed discussions of the health and risk assessments for this rule and can be viewed in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

[153] The RIA includes a more detailed discussion of the potential costs and benefits associated with this rule. It can be viewed in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

effects. Most owners/operators of existing oil and natural gas production sources on Indian country lands within the U&O Reservation also operate sources on non-Indian country lands within and outside of the U&O Reservation, where they are already required to employ the emissions control technologies required by this U&O FIP. Additionally, we expect that these owners/operators will also operate new and modified sources in the Uinta Basin that are subject to similar NSPS OOOO and OOOOa, NESHAP HH, and other oil and natural gas source category-related control requirements within the Uinta Basin. Therefore, it is expected that the owners/operators will continue to procure necessary control equipment and supplies from the same suppliers they currently use for non-Indian country existing, new or modified sources. Further, only the higher-producing sources are expected to be subject to the more substantive emission control requirements in this U&O FIP, and those sources are more likely to be able to accommodate the additional costs, so it is not expected that the new requirements alone would factor significantly into decisions to slow or halt production and thereby cause a shortfall in supply. Rather, the prices of oil and natural gas are likely to be a more significant factor in decisions on reducing production from existing sources.[154]

Additionally, this U&O FIP establishes several emissions control standards that give regulated entities flexibility in determining how to best comply with the regulation. Even within the geographically and economically homogeneous affected area within the Uinta Basin, this flexibility is an important factor in reducing regulatory burden. For more information on the estimated energy effects of the rule, please see the RIA, which is in the docket for this rule.

I. National Technology Transfer and Advancement Act (NTTAA)

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), 15 U.S.C. 272 note, directs the EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards, which include materials specifications, test methods, sampling protocols, business practices and management systems developed or adopted by voluntary consensus standards bodies (VCSB), both domestic and international. These bodies plan, develop, establish or coordinate voluntary consensus standards using agreed-upon procedures.

This action involves technical standards. Therefore, the EPA conducted a search to identify potentially applicable VCS. However, the Agency identified no such standards and none were brought to its attention in comments. [155] Therefore, the EPA has decided to use EPA Methods 21 and 22 of 40 CFR part 60, appendix A–7 and part 63, appendix A.[156]

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

While the EPA finds that communities in the Uinta Basin with higher proportions of low-income populations and people of color rank in the 90th percentile for ozone concentrations in the baseline based on EJSCREEN, the EPA concludes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations, and/or indigenous peoples, as specified in Executive Order 12898.[157]

The documentation for this decision is contained in the RIA [158] for this final rule. Our objective in developing this rule is to improve air quality and thereby protect the communities in the Uinta Basin, including those in and near Indian country lands within the U&O Reservation, where existing oil and natural gas operations have been shown to contribute to exceedances of the ozone NAAQS. The impacts of this final rule are expected to be beneficial, rather than adverse, and its benefits are expected to accrue to communities in and near Indian country lands within the U&O Reservation. As explained in Section VII.A. of this preamble, the EPA has quantified the expected emissions impacts from this final action and found that the action will result in large reductions of VOC emissions.

This final action will also provide regulatory certainty to owners/operators, by imposing, to the extent appropriate, requirements that are the same as or consistent with those applicable to such existing sources that in areas of the Basin where the EPA has approved the UDEQ to implement the CAA because they are not on Indian country lands within the Reservation. This will ensure that economic impacts are consistent and air quality is protected consistently across the Uinta Basin. Our Environmental Justice (EJ) analysis that can be found in the RIA for this rulemaking supports the conclusion that this action is not expected to result in disproportionate impacts.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 49

Environmental protection, Administrative practice and procedure, Air pollution control, Indians, Indians-law, Indians-tribal government, Intergovernmental relations, Reporting and recordkeeping requirements.

Michael S. Regan,

Administrator.

For reasons set forth in the preamble, part 49 of title 40 of the Code of Federal Regulations is amended as follows:

PART 49—INDIAN COUNTRY: AIR QUALITY PLANNING AND MANAGEMENT

■ 1. The authority citation for part 49 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

■ 2. Add the undesignated center heading ''Federal Implementation Plan for Managing Emissions from Oil and Natural Gas Sources on the Indian Country Lands Within the Uintah and Ouray Indian Reservation in Utah'' immediately following § 49.4168 and add §§ 49.4169 through 49.4184 to subpart K to read as follows:

Subpart K–Implementation Plans for Tribes–Region VIII

* * * * *

[154] The RIA includes more detailed information on oil and natural gas prices. It can be viewed in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

[155] ''Voluntary Consensus Standard Results for Federal Implementation Plan for Managing Emissions from Oil and Natural Gas Sources on the Uintah and Ouray Indian Reservation in Utah,'' Memorandum from Steffan Johnson, Group Leader, U.S. EPA, Measurement Technology Group, to Deirdre Rothery, Unit Chief Air Permitting and Monitoring Unit, U.S. EPA Region 8 Air Program, dated Dec. 22, 2017, available in the Docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

[156] The EPA Reference Methods 21 and 22 can be accessed at *https://www.ecfr.gov/cgi-bin/ECFR?page=browse* (Search Title 40, Part 60 and Part 63), accessed Mar. 14, 2022.

[157] *See* 59 FR 7629 (Feb. 16, 1994).

[158] The RIA includes a more detailed discussion of the environmental justice analysis for this rule. It can be viewed in the docket for this rulemaking (Docket ID No. EPA–R08–OAR–2015–0709).

Federal Implementation Plan for Managing Emissions From Oil and Natural Gas Sources on the Indian Country Lands Within the Uintah and Ouray Indian Reservation in Utah

Sec.
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49.4181 Other combustion devices.
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49.4183 Recordkeeping requirements.
49.4184 Notification and reporting requirements.

§ 49.4169 Introduction.

(a) *What is the purpose of §§ 49.4169 through 49.4184?* Sections 49.4169 through 49.4184 establish legally and practicably enforceable requirements for oil and natural gas sources on Indian country lands within the Uintah and Ouray Indian Reservation (U&O Reservation) to address ozone air quality. Section 49.4170 establishes provisions for delegation of authority to allow the Ute Indian Tribe to assist the EPA with administration of this Federal Implementation Plan (U&O FIP). Section 49.4171 contains general provisions and definitions applicable to oil and natural gas sources. Sections 49.4173 through 49.4184 establish legally and practicably enforceable requirements to control and reduce VOC emissions from oil and natural gas well production and storage operations, natural gas processing, and gathering and boosting operations at oil and natural gas sources that are located on Indian country lands within the U&O Reservation.

(b) *Am I subject to §§ 49.4169 through 49.4184?* Sections 49.4169 through 49.4184, as appropriate, apply to each owner or operator of an oil and natural gas source (as defined at 40 CFR 49.102) located on Indian country lands within the U&O Reservation that has equipment or activities that meet the applicability thresholds specified in each section. Generally, the equipment and activities at oil and natural gas sources that are already subject to and in compliance with VOC emission control requirements under another EPA standard or other federally enforceable requirement, as specified in each appropriate subsection later, are considered to be in compliance with the requirements to control VOC emissions from that same equipment under this U&O FIP.

(c) *When must I comply with §§ 49.4169 through 49.4184?* For oil and natural gas sources that commence construction before February 6, 2023, compliance with §§ 49.4169 through 49.4171 and §§ 49.4173 through 49.4184, as applicable, is required no later than February 6, 2024. You may submit a written request to the EPA for an extension of the compliance date for existing sources. The extension request must be submitted to the EPA at least 60 days before the compliance deadline, must identify the specific provision(s) for which you seek an extension, must include an alternative compliance deadline(s), and must provide the rationale for the requested extension with supporting information explaining how you will effectively meet all applicable requirements after the requested alternative compliance deadline. Any decision to approve or deny a request, including the length of time of an approved request, will be based on the merits of case-specific circumstances. For oil and natural gas sources that commence construction on or after February 6, 2023, compliance with §§ 49.4169 through 49.4171 and §§ 49.4173 through 49.4184, as applicable, is required upon startup.

§ 49.4170 Delegation of authority of administration to the Tribe.

(a) *What is the purpose of this section?* The purpose of this section is to establish the process by which the Regional Administrator may delegate to the Ute Indian Tribe the authority to assist the EPA with administration of this U&O FIP. This section provides for administrative delegation and does not affect the eligibility criteria under § 49.6 for treatment in the same manner as a state.

(b) *How does the Ute Indian Tribe request delegation?* To be delegated authority to assist the EPA with administration of this U&O FIP, the authorized representative of the Ute Indian Tribe must submit a written request to the Regional Administrator that:

(1) Identifies the specific provisions for which delegation is requested;

(2) Includes a statement by the Ute Indian Tribe's legal counsel (or equivalent official) with the following information:

(i) A statement that the Ute Indian Tribe is an Indian tribe recognized by the Secretary of the Interior;

(ii) A descriptive statement that meets the requirements of § 49.7(a)(2) and demonstrates that the Ute Indian Tribe is currently carrying out substantial governmental duties and powers over a defined area;

(iii) A description of the laws of the Ute Indian Tribe that provide adequate authority to carry out the aspects of the rule for which delegation is requested; and

(3) Demonstrates that the Ute Indian Tribe has, or will have, adequate resources to carry out the aspects of the rule for which delegation is requested.

(c) *How is the delegation of administration accomplished?* (1) A Delegation of Authority Agreement setting forth the terms and conditions of the delegation and specifying the provisions of this rule that the Ute Indian Tribe will be authorized to implement on behalf of the EPA will be entered into by the Regional Administrator and the Ute Indian Tribe. The Agreement will become effective on the date that both the Regional Administrator and the authorized representative of the Ute Indian Tribe have signed the Agreement. Once the delegation becomes effective, the Ute Indian Tribe will be responsible, to the extent specified in the Agreement, for assisting the EPA with administration of the FIP and will act as the Regional Administrator as that term is used in these regulations. Any Delegation of Authority Agreement will clarify the circumstances in which the term ''Regional Administrator'' found throughout the FIP is to remain the EPA Regional Administrator and when it is intended to refer to the ''Ute Indian Tribe,'' instead.

(2) A Delegation of Authority Agreement may be modified, amended, or revoked, in part or in whole, by the Regional Administrator after consultation with the Ute Indian Tribe.

(d) *How will any Delegation of Authority Agreement be publicized?* The Agency will publish a document in the **Federal Register** informing the public of any Delegation of Authority Agreement with the Ute Indian Tribe to assist the EPA with administration of all or a portion of the FIP and identifying such delegation in the FIP. The EPA will also publish an announcement of the Delegation of Authority Agreement in local newspapers.

§ 49.4171 General provisions.

(a) At all times, including periods of startup, shutdown, and malfunction, each owner or operator must, to the extent practicable, design, operate, and maintain all equipment used for crude oil, condensate, intermediate hydrocarbon liquid, or produced water, and gas collection, storage, processing, and handling operations covered under §§ 49.4171 and 49.4173 through 49.4184, regardless of emissions rate and including associated air pollution control equipment, in a manner that is consistent with good air pollution control practices and that minimizes leakage of VOC emissions to the atmosphere. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator, including monitoring results, review of operating and maintenance procedures, and inspection of the source.

(b) *Definitions.* As used in §§ 49.4169 through 49.4184, all terms not defined have the meaning given them in the Act, in 40 CFR parts 60 and 63, in the Prevention of Significant Deterioration regulations at 40 CFR 52.21, in the Federal Minor New Source Review Program in Indian Country at § 49.151, or in the Federal Implementation Plan for Managing Air Emissions from True Minor Sources in Indian Country in the Oil and Natural Gas Production and Natural Gas Processing Segments of the Oil and Natural Gas Sector at § 49.102. The following terms are defined here:

Bottom filling means the filling of a storage vessel through an inlet at or near the bottom of the storage vessel designed to have the opening covered by the liquid after the pipe normally used to withdraw liquid can no longer withdraw any liquid.

Condensate means hydrocarbon liquid separated from produced natural gas that condenses due to changes in temperature, pressure, or both, and that remains liquid at standard conditions.

Crude oil means hydrocarbon liquids that are separated from well-extracted reservoir fluids during oil and natural gas production operations, and that are stored or injected to pipelines as a saleable product. Condensate is not considered crude oil.

Electronically controlled automatic ignition device means an electronic device which generates sparks across an electrode and reaches into a combustible gas stream traveling up a flare stack or entering an enclosed combustor, at the point of the pilot tip, equipped with a temperature monitor that signals the device to attempt to re-light an extinguished pilot flame.

Enclosed combustor means a thermal oxidation system with an enclosed combustion chamber that maintains a limited constant temperature by controlling fuel and combustion air.

Flare means a thermal oxidation system using an open (without enclosure) flame that is designed and operated in accordance with the requirements of 40 CFR 60.18(b). An enclosed combustor is not considered a flare. A combustion device is not considered a flare when installed horizontally or vertically within an open pit and used to combust produced natural gas during initial well completion or temporarily during emergencies when enclosed combustors or flares installed at a source are not operational or injection of recovered produced natural gas is unavailable.

Flashing losses means natural gas emissions resulting from the presence of dissolved natural gas in the crude oil, condensate, intermediate hydrocarbon liquids or produced water, which are under high pressure that occurs as the liquids are transferred to storage vessels that are at atmospheric pressure.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of VOC at an oil and natural gas source, such as valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to § 49.4176, thief hatches or other openings on a controlled storage vessel not subject to § 49.4173, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pneumatic pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from locations other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

Glycol dehydration unit process vent emissions means VOC-containing emissions from the glycol dehydration unit regenerator or still vent and the vent from the dehydration unit flash tank (if present).

Indian country is defined at 18 U.S.C. 1151 and means.

(i) All land within the limits of any Indian reservation under the jurisdiction of the United States Government, notwithstanding the issuance of any patent, and, including rights-of-way running through the reservation,

(ii) All dependent Indian communities within the borders of the United States whether within the original or subsequently acquired territory thereof, and whether within or without the limits of a state, and

(iii) All Indian allotments, the Indian titles to which have not been extinguished, including rights-of-way running through the same.

Intermediate hydrocarbon liquids means any naturally occurring, unrefined petroleum liquid.

Malfunction alarm and remote notification system means a system connected to an electronically controlled automatic ignition device that sends an alarm through a remote notification system to an owner or operator's central control center, if an attempt to relight the pilot flame is unsuccessful.

Pneumatic controller means a *natural gas-driven pneumatic controller* as defined at 40 CFR 60.5430 and 60.5430a.

Pneumatic pump means a *natural gas-driven diaphragm pump* as defined at 40 CFR 60.5430a.

Pneumatic pump emissions means the VOC-containing emissions from pneumatic pumps.

Produced natural gas means natural gas that is separated from extracted reservoir fluids during oil and natural gas production operations.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Regional Administrator means the Regional Administrator of EPA Region 8 or an authorized representative of the Regional Administrator of EPA Region 8, except to the extent otherwise specifically specified in a Delegation of Authority Agreement between the Regional Administrator and the Ute Indian Tribe.

Repaired means, for the purposes of fugitive emissions components, that fugitive emissions components are adjusted, replaced, or otherwise altered in order to eliminate fugitive emissions as defined in § 49.4178(d)(1)(iii), and subsequently monitored as specified in § 49.4178(d)(1)(ii), and that it is verified that emissions from the fugitive emissions components are below the applicable fugitive emissions definition.

Standing and breathing losses means VOC emissions from fixed-roof storage vessels as a result of evaporative losses during storage.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of non-earthen materials (such as wood, concrete, steel, fiberglass, or plastic), which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel will not be considered a storage vessel if it has been removed from service in accordance with the requirements of § 49.4173(a)(3), until that tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

(i) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by § 49.4183(a)(1)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel is considered to be a storage vessel from the date it was first located at the site. This exclusion does not apply to a well completion vessel as described above.

(ii) Process vessels such as surge control vessels, bottoms receivers, and knockout vessels.

(iii) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

Submerged fill pipe means any fill pipe with a discharge opening that is entirely submerged when the liquid level is six inches above the bottom of the storage vessel and the pipe normally used to withdraw liquid from the storage vessel can no longer withdraw any liquid.

Supervisory Control and Data Acquisition (SCADA) system generally refers to industrial control computer systems that monitor and control industrial infrastructure or source-based processes.

Unsafe to repair means (in the context of fugitive emissions monitoring) that operator personnel would be exposed to an imminent or potential danger as a consequence of the attempt to repair the leak during normal operation of the source.

Visible smoke emissions means air pollution generated by thermal oxidation in a flare or enclosed combustor and occurring immediately downstream of the flame present in those units. Visible smoke occurring within, but not downstream of, the flame, does not constitute visible smoke emissions.

Working losses means natural gas emissions from fixed roof storage vessels resulting from evaporative losses during filling and emptying operations.

§ 49.4172 Emissions inventory.

(a) *Applicability.* The emissions inventory requirements of this section apply to each oil and natural gas source, as identified in § 49.4169(b), that has actual emissions of any pollutant identified in paragraph (c) of this section greater than or equal to one ton in any consecutive 12-month period.

(b) Each oil and natural gas source must submit an inventory for every third year, beginning with the 2023 calendar year, for all emission units at a source.

(c) The inventory must include the total emissions for PM_{10}, $PM_{2.5}$, oxides of sulfur, nitrogen oxides, carbon monoxide, and volatile organic compounds, as defined at 40 CFR 51.50, for each emissions unit at the source. Emissions for each emissions unit at the source must be calculated using the emissions unit's actual operating hours, appropriate emissions rates, the use of performance test results where applicable, product rates and types of materials processed, stored, or combusted during the calendar year of the reporting period.

(d) The inventory must include the type and efficiency, for each pollutant controlled, of any air pollution control equipment present at the reporting source. The detail of the emissions inventory must be consistent with the detail and data elements required by 40 CFR part 51, subpart A.

(e) The inventory must be submitted to the EPA no later than April 15th of the year following each inventory year.

(f) The inventory must be submitted in an electronic format specific to this source category, as instructed on the EPA Region 8 website at *https://www.epa.gov/air-quality-implementation-plans/approved-air-quality-implementation-plans-region-8.*

§ 49.4173 VOC emissions control requirements for storage vessels.

(a) *Applicability.* The VOC emissions control requirements of this section apply to storage vessels at an oil and natural gas source (as specified in § 49.4169(b)) as follows:

(1) For oil and natural gas sources that began operations before February 6, 2023, the VOC emissions control requirements of this section apply when the source-wide potential for VOC emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps is equal to or greater than 4 tpy, as determined according to this section. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production during the 12 months before the compliance deadline for the affected source under this rule. The determination may take into account requirements under a legally and practicably enforceable limit in an operating permit or other federally enforceable requirement. You must reevaluate the source-wide VOC emissions from the collection of all storage vessels, glycol dehydrators and pneumatic pumps for each modification to an existing source; or

(2) For oil and natural gas sources that began operations on or after February 6, 2023, the VOC emissions control requirements of this section apply upon startup of operation.

(3) Modification to an oil and natural gas source requires a re-evaluation of the source-wide VOC emissions from the collection of all storage vessels, glycol dehydrators and pneumatic pumps. Adding production from a new well or increasing production at an existing well is considered a modification of a well site. Increasing maximum throughput at a tank battery, compressor station or natural gas processing plant is considered a modification.

(b) *Exemptions.* (1) This section does not apply to storage vessels located at an oil and natural gas source that are subject to the emissions control requirements for storage vessels in 40 CFR part 60, subparts OOOO or OOOOa, or 40 CFR part 63, subpart HH.

(2) This section does not apply to an emergency storage vessel located at an oil and natural gas source, if it meets the following requirements:

(i) The emergency storage vessel is not used as an active storage vessel;

(ii) The owner or operator empties the emergency storage vessel no later than 15 days after receiving fluids;

(iii) The emergency storage vessel is equipped with a liquid level gauge or equivalent device; and

(iv) Records are kept of the usage of each emergency storage vessel as required in § 49.4183(a)(3), including the date the vessel received fluids, the volume of fluids received in barrels, the date the vessel was emptied, and the volume of fluids emptied in barrels.

(3) This section does not apply to storage vessels that are removed from service. If you remove a storage vessel from service, you must comply with paragraphs (b)(3)(i) through (iii) of this section.

(i) For a storage vessel to be removed from service, you must comply with the requirements of paragraphs (b)(3)(i)(A) and (B) of this section.

(A) You must completely empty and degas the storage vessel, such that the storage vessel no longer contains crude oil, condensate, intermediate hydrocarbon liquids or produced water. A storage vessel where liquid is left on walls, as bottom clingage, or in pools due to floor irregularity is considered to be completely empty.

(B) You must keep records as required in § 49.4183(a)(4), identifying each storage vessel removed from service and the date of its removal from service.

(ii) If a storage vessel identified in paragraph (b)(3)(i)(B) of this section is returned to service, you must determine its applicability as provided in paragraph (a) of this section, and you must keep records as required in § 49.4183(a)(4), identifying the storage vessel and the date of its return to service.

(c) *VOC emission control requirements.* For each storage vessel, you must comply with the VOC emissions control requirements of paragraph (c)(1) or (c)(2) of this section.

(1) You must reduce VOC emissions from each storage vessel by at least 95.0 percent on a continuous basis according to paragraph (c)(1)(i) or (ii) of this section. You must equip each storage vessel with a cover that meets the conditions specified in § 49.4176(c), and must route all flashing, working, standing and breathing losses from the storage vessels through a closed-vent system that meets the conditions specified in § 49.4176(d) to:

(i) An operating system designed to recover 100 percent of the emissions and recycle them for use in a process unit or incorporate them into a product; or

(ii) An enclosed combustor or flare that is designed to reduce the mass content of VOC in the natural gas emissions vented to the device by at least 95.0 percent and that is operated as specified in § 49.4177;

(2) You must maintain the source-wide uncontrolled actual VOC emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps at an oil and natural gas source at less than 4 tpy. Before using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained at less than 4 tpy, as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology. Monthly calculations must be based on the average throughput of the source for the month. Monthly calculations must be separated by at least 14 days. You must comply with paragraph (c)(1) of this section within 30 days of the monthly emissions determination required in this section if the determination indicates that VOC emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps at your oil and natural gas source increased to 4 tpy or greater.

(3) Except as provided in paragraph (c)(4) of this section, if you use a control device to reduce emissions from your storage vessels, you must equip each storage vessel with a cover that meets the requirements of § 49.4176(c).

(4) If you use a floating roof to reduce emissions, you must meet the requirements of § 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(5) After a minimum of 12 consecutive months of operation at a source that begins operation on or after February 6, 2023, controls may be removed if the source-wide uncontrolled actual VOC emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps has been maintained at a rate less than 4 tpy, as determined according to paragraph (c)(2) of this section.

§ 49.4174 VOC emissions control requirements for dehydrators.

(a) *Applicability.* The VOC emissions control requirements of this section apply to each glycol dehydration unit located at an oil and natural gas source as identified in § 49.4169(b) where the source-wide potential for VOC emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps is equal to or greater than 4 tpy, as determined according to § 49.4173. You must reevaluate the source-wide VOC emissions from the collection of all storage vessels, glycol dehydrators and pneumatic pumps for each modification to an existing source, as described in § 49.4173(a)(3). Applicability for glycol dehydrators that began operation before February 6, 2023 must be determined using uncontrolled actual emissions. Applicability for glycol dehydrators that began operation on or after February 6, 2023 must be determined using potential to emit.

(b) *Exemptions.* This section does not apply to glycol dehydration units subject to the emissions control requirements for glycol dehydration unit process vents in 40 CFR part 63, subpart HH.

(c) *VOC emissions control requirements.* For each glycol dehydration unit, you must comply with the VOC emissions control requirements of paragraphs (c)(1) or (2) of this section.

(1) You must reduce VOC emissions from each glycol dehydration unit process vent by at least 95.0 percent on a continuous basis according to paragraphs (c)(1)(i) and (ii) of this section. You must route all glycol dehydration unit process vent emissions through a closed-vent system that meets the conditions specified in § 49.4176(d) to:

(i) An operating system designed to recover 100 percent of the emissions and recycle them for use in a process unit or incorporate them into a product; or

(ii) An enclosed combustor or flare designed to reduce the mass content of VOC in the emissions vented to the device by at least 95.0 percent and operated as specified in § 49.4177; or

(2) You must maintain the source-wide uncontrolled actual VOC emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps at an oil and natural gas source at less than 4 tpy for 12 consecutive months in accordance with the procedures specified in § 49.4173(c)(2).

§ 49.4175 VOC emissions control requirements for pneumatic pumps.

(a) *Applicability.* The requirements of this section apply to each pneumatic pump located at an oil and natural gas source as identified in § 49.4169(b) where the source-wide potential for VOC emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps is equal to or greater than 4 tpy, as determined according to § 49.4173. You must reevaluate the source-wide VOC emissions from the collection of all storage vessels, glycol dehydrators and pneumatic pumps for each modification to an existing source, as described in § 49.4173(a)(3). Applicability for pneumatic pumps that began operation before February 6, 2023 must be determined using uncontrolled actual emissions. Applicability for pneumatic pumps that began operation on or after February 6, 2023 must be determined using potential to emit.

(b) *Exemptions.* This section does not apply to pneumatic pumps subject to the emissions control requirements for pneumatic pumps in 40 CFR part 60, subpart OOOOa.

(c) *VOC Emission Control Requirements.* For each pneumatic pump, you must comply with the VOC emissions control requirements of paragraph (c)(1) or (2) of this section.

(1) You must reduce VOC emissions from each pneumatic pump by at least 95.0 percent on a continuous basis according to paragraph (c)(1)(i) or (ii) of this section. You must route all pneumatic pump emissions through a closed-vent system that meets the conditions specified in § 49.4176(d) to:

(i) An operating system designed to recover 100 percent of the emissions and recycle them for use in a process unit or incorporate them into a product; or

(ii) An enclosed combustor or flare designed to reduce the mass content of VOC in the emissions vented to the device by at least 95.0 percent and operated as specified in § 49.4177; or

(2) You must maintain the source-wide uncontrolled actual VOC emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps at an oil and natural gas source at less than 4 tpy for any 12 consecutive months in accordance with the procedures specified in § 49.4173(c)(2).

§ 49.4176 VOC emissions control requirements for covers and closed-vent systems.

(a) *Applicability.* The VOC emissions control requirements in this section apply to each cover on a storage vessel that is subject to § 49.4173, and to each closed-vent system that is used to convey VOC emissions from the collection of all storage vessels, glycol dehydration units, or pneumatic pumps (to a vapor recovery system or control device) that are subject to §§ 49.4173 through 49.4175.

(b) *Exemptions.* This section does not apply to covers and closed-vent systems that are subject to the requirements for covers and closed-vent systems in 40 CFR part 60, subparts OOOO or OOOOa, or 40 CFR part 63, subpart HH.

(c) *Covers.* Each owner or operator must equip all openings on each storage vessel with a cover to ensure that all flashing, working, standing and breathing loss emissions are routed through a closed-vent system to a vapor recovery system, an enclosed combustor, or a flare.

(1) Each cover and all openings on the cover (*e.g.,* access hatches, sampling ports, pressure relief valves (PRV), and gauge wells) must form a continuous impermeable barrier over the entire surface area of the crude oil, condensate, intermediate hydrocarbon liquids, or produced water in the storage vessel.

(2) Each cover opening must be secured in a closed, sealed position (*e.g.,* covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except when it is necessary to use an opening as follows:

(i) To add fluids to, or remove fluids from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the fluids in the unit; or

(iii) To inspect, maintain, repair, or replace equipment located inside the unit.

(3) Each thief hatch cover must be weighted and properly seated to ensure that flashing, working, standing, and breathing loss emissions are routed through the closed-vent system to the vapor recovery system, the enclosed combustor, or the flare under normal operating conditions.

(4) Each PRV must be set to release at a pressure that will ensure that flashing, working, standing, and breathing loss emissions are routed through the closed-vent system to the vapor recovery system, the enclosed combustor, or the flare under normal operating conditions.

(d) *Closed-vent systems.* Each owner or operator must meet the following requirements for closed-vent systems:

(1) Each closed-vent system must route all captured storage vessel emissions from flashing, working, standing, and breathing losses; glycol dehydration unit process vent emissions; and pneumatic pump emissions from the oil and natural gas source to a gathering pipeline system for sale, use in a process unit, incorporation into a product, or other beneficial purpose, or to a VOC emission control device, as specified in §§ 49.4173 through 49.4175.

(2) All vent lines, connections, fittings, valves, relief valves, and any other appurtenances employed to collect or contain captured storage vessel emissions from flashing, working, standing, and breathing losses; glycol dehydration unit process vent emissions; or pneumatic pump emissions; or to transport such emissions to a gathering pipeline system for sale, use in a process unit, incorporation into a product, or other beneficial purpose, or to a VOC emission control device, as specified in §§ 49.4173 through 49.4175, must be maintained and operated properly at all times.

(3) Each closed-vent system must be designed to operate with no detectable emissions, as demonstrated by the closed-vent system monitoring requirements in § 49.4182(c).

(4) If any closed-vent system contains one or more bypass devices that could be used to divert all or a portion of the captured storage vessel flashing, working, standing, and breathing losses; glycol dehydration unit process vent emissions; or pneumatic pump emissions from entering a gathering pipeline system for sale, use in a process unit, incorporation into a product, or other beneficial purpose, or from being transferred to the VOC emissions control device, the owner or operator must meet one of the requirements in paragraphs (d)(4)(i) or (ii) of this section for each bypass device. Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements applicable to bypass devices.

(i) At the inlet to a bypass device the owner or operator must properly install, calibrate, maintain, and operate a flow indicator that is capable of taking continuous readings and sounding an alarm when the bypass device is open such that emissions are being, or could be, diverted away from a gathering pipeline system for sale, use in a process unit, incorporation into a product, or other beneficial purpose, or the VOC emission control device and into the atmosphere; or

(ii) The owner or operator must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

§ 49.4177 VOC emissions control devices.

(a) *Applicability.* The requirements in this section apply to all flares and enclosed combustors used to control VOC emissions at an oil and natural gas source, as identified in § 49.4169(b), in order to meet the requirements specified in §§ 49.4173 through 49.4176, as applicable.

(b) *Exemptions.* This section does not apply to VOC emission control devices that are subject to the requirements for control devices used to comply with the emissions standards in 40 CFR part 60, subparts OOOO or OOOOa; or 40 CFR part 63, subpart HH.

(c) *Enclosed combustors and flares.* Each owner or operator must meet the following requirements for enclosed combustors and flares:

(1) For each enclosed combustor or flare, the owner or operator must follow the manufacturer's written operating instructions, procedures, and

maintenance schedule to ensure good air pollution control practices for minimizing emissions;

(2) The owner or operator must ensure that each enclosed combustor or flare is designed to have sufficient capacity to reduce the mass content of VOC in the captured emissions routed to it by at least 95.0 percent for the minimum and maximum natural gas volumetric flow rate and BTU content routed to the device;

(3) Each enclosed combustor or flare must be operated to reduce the mass content of VOC in the captured emissions routed to it by continuously meeting at least 95.0 percent VOC control efficiency;

(4) The owner or operator must ensure that each flare is designed and operated in accordance with the requirements of 40 CFR 60.18(b) for such flares;

(5) The owner or operator must ensure that each enclosed combustor is:

(i) A model that is:

(A) Demonstrated by a manufacturer to meet the VOC control efficiency requirements of §§ 49.4173 through 49.4176 using EPA-approved performance test procedures specified in 40 CFR 60.5413; or

(B) Demonstrated by the owner or operator to meet the VOC control efficiency requirements of §§ 49.4173 through 49.4176 according to the procedures and schedule specified in § 49.4182(d)(1);

(ii) Operated properly at all times that captured emissions are routed to it;

(iii) Operated with a liquid knock-out system to collect any condensable vapors (to prevent liquids from going through the control device);

(iv) Equipped and operated with a flash-back flame arrestor;

(v) Equipped and operated with one of the following:

(A) A continuous burning pilot; or

(B) An operational electronically controlled automatic ignition device;

(vi) Equipped with a monitoring system for continuous measuring and recording of the parameters that indicate proper operation of each enclosed combustor or flare, including each continuous burning pilot flame or electronically controlled automatic ignition device, to monitor and document proper operation of the enclosed combustor or flare. Examples of such continuous monitoring systems may include a thermocouple and a chart recorder, data logger or similar device, or connection to a SCADA system;

(vii) Maintained in a leak-free condition; and

(viii) Operated with no visible smoke emissions.

(d) *Other control devices.* Upon prior written approval by the EPA, the owner or operator may use control devices other than those listed above that are determined by the EPA to be capable of reducing the mass content of VOC in the natural gas routed to it by at least 95.0 percent, provided that:

(1) In operating such control devices, the owner or operator must follow the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions; and

(2) The owner or operator must ensure there is sufficient capacity to reduce the mass content of VOC in the produced natural gas and natural gas emissions routed to such other control devices by at least 95.0 percent for the minimum and maximum natural gas volumetric flow rate and BTU content routed to each device.

(3) The owner or operator must operate such a control device to reduce the mass content of VOC in the produced natural gas and natural gas emissions routed to it by at least 95.0 percent.

§ 49.4178 VOC emissions control requirements for fugitive emissions.

(a) *Applicability.* The requirements of this section apply to all owners or operators of the collection of fugitive emissions components, as defined in § 49.4171, located at any oil and natural gas source, as identified in § 49.4169(b), except that this section does not apply to owners or operators of the collection of fugitive emissions components at an oil and natural gas source that is subject to the fugitive emissions monitoring requirements in 40 CFR part 60, subpart OOOOa.

(b) Owners or operators of the collection of fugitive emissions components must comply with paragraph (d) of this section if either of the following is true:

(1) The collection of fugitive emissions components is located at an oil and natural gas source that is required to control VOC emissions according to §§ 49.4173 through 49.4177 of this section (*i.e.,* the source-wide potential for VOC emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps is equal to or greater than 4 tpy, as determined according to § 49.4173(a)(1)); or

(2) The collection of fugitive emissions components is located at a well site, as defined in 40 CFR 60.5430a, that at any time has total production greater than 15 barrels of oil equivalent (boe) per day based on a rolling 12-month average.

(c) Owners or operators of the collection of fugitive emissions components for which neither (b)(1) nor (b)(2) is true must comply with either paragraph (c)(1) or paragraph (c)(2) of this section.

(1) You must monitor all fugitive emissions components and repair all sources of fugitive emissions in accordance with paragraph (d) of this section. You must keep records in accordance with § 49.4183 and report in accordance with § 49.4184; or

(2) You must maintain the total production for the well site at or below 15 boe per day based on a rolling 12-month average. You must demonstrate that the total daily oil and natural gas production from the collection of all wells producing to the well site is at or below 15 boe per day, based on a 12-month rolling average, according to the procedures in paragraph (e) of this section. You must maintain records as specified in § 49.4183(a)(11).

(d) *Monitoring requirements.* (1) Each owner or operator must develop and implement a fugitive emissions monitoring plan to reduce emissions from fugitive emissions components at all of their oil and natural gas sources on Indian country lands within the U&O Reservation. This Reservation-wide monitoring plan must include the following elements, at a minimum:

(i) A requirement to perform an initial monitoring of the collection of fugitive emissions components at each oil and natural gas source by February 6, 2024;

(ii) A requirement to perform subsequent monitoring of the collection of fugitive emissions components at each oil and natural gas source once every 6 months after the initial monitoring survey, with consecutive monitoring surveys conducted at least 4 months apart and no more than 7 months apart.

(iii) A description of the technique used to identify leaking fugitive emission components, which must be limited to:

(A) Onsite EPA Reference Method 21, 40 CFR part 60, appendix A, where an analyzer reading of 500 parts per million volume (ppmv) VOC or greater is considered a leak in need of repair;

(B) Onsite optical gas imaging instruments, as defined in 40 CFR 60.18(g)(4), where any visible emissions are considered a leak in need of repair, unless the owner or operator evaluates the leak with an analyzer meeting EPA Reference Method 21 at 40 CFR part 60, appendix A, and the concentration is less than 500 ppmv. The optical gas imaging instrument must be capable of meeting the optical gas imaging equipment requirements specified in 40 CFR part 60, subpart OOOOa; or

(C) Another method approved by the Administrator to demonstrate compliance with the fugitive emissions monitoring requirements. To be approved, you must demonstrate that the alternative method achieves emissions reductions that equal or exceed those that would result from the application of either Method 21 or optical gas imaging instruments. Approval of an alternative method will be subject to public notice and comment.

(iv) The manufacturer and model number of any fugitive emissions monitoring device to be used;

(v) Procedures and timeframes for identifying and repairing components from which leaks are detected, including:

(A) A requirement to repair any leaks identified from components that are safe to repair and do not require source shutdown as soon as practicable, but no later than 30 calendar days after discovering the leak;

(B) Timeframes for inspecting and repairing leaking components that are difficult-to-monitor, unsafe-to-monitor, or require source shutdown, to be no later than the next required monitoring event, as noted in paragraphs (c)(1)(v)(B)(*1*) through (*3*) of this section:

(*1*) If using Method 21, fugitive emissions components that cannot be monitored without elevating the monitoring personnel more than 2 meters above the surface may be designated as difficult-to-monitor and must meet the specifications in paragraphs (c)(1)(v)(B)(*1*)*(i)* through *(iv)* of this section:

(i) For all fugitive emissions components designated difficult-to-monitor, a written plan must be developed and incorporated into the fugitive emissions monitoring plan.

(ii) The plan must include the identification and location of each fugitive emissions component designated difficult-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as difficult-to-monitor is difficult-to-monitor.

(iv) The plan must include a schedule for monitoring the difficult-to-monitor fugitive emissions components at least once per calendar year and a schedule for repairing such fugitive emissions components according to paragraph (c)(1)(v)(B)(*3*) of this section;

(*2*) Fugitive emissions components that cannot be monitored because monitoring personnel would be exposed to an immediate danger while conducting a monitoring survey may be designated as unsafe-to-monitor and must meet the specification in paragraphs (c)(1)(v)(B)(*2*)*(i)* through *(iv)* of this section:

(i) A written plan must be developed for all of the fugitive emissions components designated unsafe-to-monitor and incorporated into the fugitive emissions monitoring plan;

(ii) The plan must include the identification and location of each fugitive emissions component designated unsafe-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as unsafe-to-monitor is unsafe-to-monitor.

(iv) The plan must include a schedule for monitoring the unsafe-to-monitor fugitive emissions components as frequently as practicable during safe to inspect times and for repairing such fugitive emissions components according to paragraph (c)(1)(v)(B)(*3*) of this section;

(*3*) If the repair or replacement of a fugitive emissions component designated difficult-to-monitor or unsafe-to-monitor is technically infeasible; would require a vent blowdown, a compressor station shutdown, a well shutdown, or well shut-in; or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next scheduled compressor station shutdown, well shutdown, or well shut-in; after a planned vent blowdown; or within 2 years, whichever is earlier; and

(C) Procedures for verifying leaking component repairs, no more than 30 calendar days after repairing the leak;

(vi) Training and experience needed before performing surveys;

(vii) Procedures for calibration and maintenance of any fugitive emissions monitoring device to be used; and

(viii) Standard monitoring protocols for each type of typical oil and natural gas source (*e.g.,* well site, tank battery, compressor station), including a general list of component types that will be inspected and what supporting data will be recorded (*e.g.,* wind speed, detection method device-specific operational parameters, date, time, and duration of inspection).

(2) The owner or operator is exempt from inspecting and repairing a fugitive emissions component under any of the following circumstances:

(i) The contacting process stream only contains glycol, amine, methanol, or produced water; or

(ii) The component to be inspected is buried, insulated in a manner that prevents access to the components by a monitor probe or optical gas imaging device, or obstructed by equipment or piping that prevents access to the components by a monitor probe or optical gas imaging device.

(e) *Procedures for determining total well site production.* The total well site production must be determined according to the following procedures:

(1) Calculate the total average boe per day for each calendar month using:

(i) For existing well sites, the records of production for the first 30 days after becoming subject to this section.

(ii) For well sites that commence construction, reconstruction or modification on or after February 6, 2023, the first 30 days of production, performing the calculation within 45 days of the end of the first 30 days of production.

(2) Determine the daily oil and natural gas production for each individual well at the well site for the month. To convert gas production to equivalent barrels of oil, divide the cubic feet of gas produced by 6,000.

(3) Sum the daily production for each individual well at the well site to determine the total well site production and divide by the total number of days in the calendar month. This is the average daily total well site production for the month.

(4) Use the result determined in paragraph (e)(2) of this section and average with the daily average well site production values determined for each of the preceding 11 months to calculate the rolling 12-month average of the total well site production.

§ 49.4179 VOC emissions control requirements for tank truck loading.

(a) *Applicability.* The requirements in this section apply to each owner or operator who loads or permits the loading of any intermediate hydrocarbon liquid or produced water at an oil and natural gas source as identified in § 49.4169(b).

(b) *Tank truck loading requirements.* Tank trucks used for transporting intermediate hydrocarbon liquid or produced water must be loaded and unloaded using measures to minimize VOC emissions. These measures must include, at a minimum, bottom filling or a submerged fill pipe, as defined in § 49.4171(b).

§ 49.4180 VOC emissions control requirements for pneumatic controllers.

(a) *Applicability.* The VOC emissions control requirements in this section apply to each owner or operator of any existing pneumatic controller located at an oil and natural gas source as identified in § 49.4169(b).

(b) *Exemptions.* This section does not apply to pneumatic controllers subject to and controlled in accordance with the requirements for pneumatic controllers in 40 CFR part 60, subparts OOOO or OOOOa.

(c) *Retrofit requirements.* All existing pneumatic controllers must meet the standards established for pneumatic controllers that are constructed, modified, or reconstructed on or after October 15, 2013, as specified in 40 CFR part 60, subpart OOOO.

(d) *Documentation requirements.* The owner or operator of any existing pneumatic controllers must meet the tagging requirements in 40 CFR 60.5390(a), except that the month and year of installation, reconstruction or modification is not required.

§ 49.4181 Other combustion devices.

(a) *Applicability.* The VOC emission control requirements in this section apply to each owner or operator of any existing enclosed combustor or flare located at an oil and natural gas source as identified in § 49.4169(b) that is used to control VOC emissions, but that is not required under §§ 49.4173 through 49.4175 of this rule.

(b) *Retrofit requirements.* All existing enclosed combustors and flares must be equipped with an operational electronically controlled automatic ignition device.

§ 49.4182 Monitoring and testing requirements.

(a) *Applicability.* The monitoring and testing requirements in paragraphs (c) and (d) of this section apply, as appropriate, to each oil and natural gas source as identified in § 49.4169(b) with equipment or activities that are subject to §§ 49.4173 through 49.4177.

(b) *Exemptions.* Paragraphs (c) and (d) of this section do not apply to any storage vessels, glycol dehydration units, pneumatic pumps, covers, or closed-vent systems, or to VOC emission control devices subject to and monitored in accordance with the monitoring requirements for such equipment and activities in 40 CFR part 60, subparts OOOO or OOOOa, or 40 CFR part 63, subpart HH.

(c) Each owner or operator must inspect each cover and closed-vent system as specified in paragraphs (c)(1) or (2).

(1) Conduct olfactory, visual, and auditory inspections at least once every calendar month, separated by at least 15 days between each inspection, of each cover and closed-vent system, including each bypass device, and each storage vessel thief hatch, seal, and pressure relief valve, to ensure proper condition and functioning of the equipment to identify defects that can result in air emissions according to the procedures. Examples of defects are visible cracks, holes, or gaps in the cover or piping, or between the cover and the separator wall; loose connections; liquid leaks; and broken, cracked, or otherwise damaged seals or gaskets on closure devices, caps, or other closure devices. If the storage vessel is partially or entirely buried, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells) and can be opened to the atmosphere. The inspector should note whether there are signs of oil releases around storage vessel thief hatches, seals and pressure relief valves (*e.g.,* staining on the storage vessel), which may indicate over-pressure events that occurred when the storage vessel was being filled. Any defects identified must be corrected or repaired within 30 days of identification.

(2) Conduct optical gas imaging inspections of each cover and closed vent system for any visible emissions at the same frequency as the frequency for the collection of fugitive emissions components located at the oil and natural gas source, as specified in § 49.4178(d)(1).

(d) Each owner or operator must monitor the operation of each enclosed combustor and flare to confirm proper operation and demonstrate compliance with the requirements of § 49.4177(c), as follows and as applicable:

(1) Demonstrate compliance with the requirement of § 49.4177(c)(5)(i)(B) that each enclosed combustor must be demonstrated by the owner or operator to meet the VOC control efficiency requirements of §§ 49.4173 through 49.4176, by conducting performance tests using EPA-approved performance test methods and procedures specified in 40 CFR 60.5413 and according to the schedule specified in paragraphs (d)(1)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after the effective date of this rule for existing enclosed combustors, and within 180 days after initial startup for new enclosed combustors. You must submit the performance test results as specified in § 49.4184(a) within 60 days of completing the test.

(ii) You must conduct periodic performance tests for all enclosed combustors required to conduct initial performance tests. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (d)(1)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in § 49.4184(a) within 60 days of completing each test.

(iii) The owner or operator of an enclosed combustor whose model is tested under, and meets the criteria of, § 49.4177(c)(5)(i)(A) is not required to conduct performance testing.

(2) Conduct inspections of each enclosed combustor or flare at least once every calendar month, separated by at least 15 days between each inspection, to confirm proper operation of the device, as follows:

(i) Demonstrate that each enclosed combustor or flare is operated with no visible smoke emissions, except for periods not to exceed a total of 1 minute during any 15-minute period, by conducting a visible emissions test using section 11 of EPA Method 22 of appendix A–7 of 40 CFR part 60. The observation period must be of sufficient length to meet the requirement for determining compliance with this visible emissions standard. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair, and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22 of Appendix A–7 of 40 CFR part 60 visual observation as described in this paragraph.

(ii) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the device and that the continuous burning pilot or electronically controlled automatic ignition device and the continuous parameter monitoring system is operating properly;

(iii) Conduct olfactory, visual and auditory inspections of all other equipment associated with the combustion device to ensure system integrity; and

(iv) Respond to any indication of pilot flame failure and ensure that the pilot flame is relit as soon as practically and safely possible after discovery.

(e) Where sufficient to meet the monitoring requirements in this section, the owner or operator may use a SCADA system to monitor and record the required data.

§ 49.4183 Recordkeeping requirements.

(a) Each owner or operator of an oil and natural gas source as identified in § 49.4169(b) must maintain the following records, as applicable:

(1) Monthly calculations, as specified in § 49.4173(c)(2), demonstrating that the uncontrolled actual VOC emissions from the collection of all storage vessels, glycol dehydrators, and pneumatic pumps at an oil and natural gas source, as identified in § 49.4169(b), have been maintained at less than 4 tpy;

(2) Records of monthly and rolling 12-month crude oil, condensate, intermediate hydrocarbon liquids, produced water or natural gas throughput;

(3) For each emergency storage vessel that is exempted from the control requirements of § 49.4173(b)(2), records of usage including:

(i) The date the vessel received fluids;

(ii) The volume of fluids received in barrels;

(iii) The date the overflow vessel was emptied; and

(iv) The volume of fluids emptied in barrels.

(4) Identification of each storage vessel that is removed from service or returned to service as specified in § 49.4173(b)(3), including the date the storage vessel was removed from service or returned to service.

(5) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), records indicating the number of consecutive days that the vessel is located at an oil and natural gas source. If a storage vessel is removed from an oil and natural gas source and, within 30 days, is either returned to the source or replaced by another storage vessel at the source to serve the same or similar function, then the entire period since the original storage vessel was first located at the source, including the days when the storage vessel was removed, must be added to the count of the number of consecutive days.

(6) For each enclosed combustor or flare at an oil and natural gas source required under §§ 49.4173 through 49.4177:

(i) Manufacturer-written, site-specific designs, operating instructions, operating procedures and maintenance schedules, including those of any operation monitoring systems;

(ii) Date of installation;

(iii) Records of required monitoring of operations in § 49.4182(d)(1);

(iv) Records of any instances in which the pilot flame is not present or the monitoring equipment is not functioning in the enclosed combustor or flare, the date and times of the occurrence, the corrective actions taken, and any preventative measures adopted to prevent recurrence of the occurrence; and

(v) Records of any visible emissions tests conducted according to § 49.4182(d)(3), including any time periods in which visible smoke emissions are observed emanating from the enclosed combustor or flare.

(7) For each closed-vent system:

(i) The date of installation; and

(ii) Records of any instances in which any closed-vent system or control device was bypassed or down, the reason for each incident, its duration, and the corrective actions taken, and any preventative measures adopted to avoid such bypasses or downtimes.

(8) Documentation of all storage vessel and closed-vent system inspections required in § 49.4182(c). All inspection records must include the following information:

(i) The date of the inspection;

(ii) The findings of the inspection;

(iii) Any adjustments or repairs made as a result of the inspection, and the date of the adjustment or repair; and

(iv) The inspector's name or identification number;

(9) The Uinta Basin-wide fugitive emissions monitoring plan for the Indian country lands within the U&O Reservation, including all elements required by § 49.4178(d).

(10) Documentation of each fugitive emissions inspection conducted in accordance with § 49.4178(d). All inspection records must include the following information:

(i) The date of the inspection;

(ii) The identification of any component that was determined to be leaking;

(iii) The identification of any component designated difficult-to-monitor or unsafe-to-monitor that was not inspected, and the reason it was not inspected;

(iv) The date of the first attempt to repair the leaking component;

(v) The identification of any leaking component with a delayed repair and the reason for the delayed repair:

(A) For unavailable parts:

(*1*) The date of ordering a replacement component; and

(*2*) The date the replacement component was received; and

(B) For a shutdown:

(*1*) The reason the repair is technically infeasible;

(*2*) The date of the shutdown;

(*3*) The date of subsequent startup after a shutdown; and

(*4*) Emission estimates of the shutdown and the repair if the delay is longer than 6 months;

(vi) The date and description of any corrective action taken, including the date the component was verified to no longer be leaking;

(vii) The identification of each component exempt under § 49.4178(d)(2), including the type of component and a description of the qualifying exemption; and

(viii) The inspector's name or identification number.

(11) For each well site complying with either § 49.4178(b)(2) or § 49.4178(c)(2), you must maintain records of the rolling 12-month average daily production no later than 12 months before complying with § 49.4178(b)(2) or § 49.4178(c)(2).

(12) For each electronically controlled automatic ignition system required under § 49.4181, records demonstrating the date of installation and manufacturer specifications; and

(13) For each retrofitted pneumatic controller, the records required in 40 CFR 60.5420(c)(4)(i).

(b) Each owner or operator must keep all records required by this section onsite at the source or at the location that has day-to-day operational control over the source and must make the records available to the EPA upon request.

(c) Each owner or operator must retain all records required by this section for a period of at least 5 years from the date the record was created.

§ 49.4184 Notification and reporting requirements.

(a) Unless otherwise specified, each owner or operator must submit any documents required under this rule to: U.S. EPA Region 8, Enforcement and Compliance Assurance Division, Air and Toxics Enforcement Branch, 8ENF–AT, 1595 Wynkoop St., Denver, CO 80202, or documents may be submitted electronically to *r8airreportenforcement@epa.gov* and/or to the EPA's Compliance and Emissions Data Reporting Interface (CEDRI). Information on CEDRI is available at *https://www.epa.gov/electronic-reporting-air-emissions/cedri;* CEDRI can be accessed directly through the EPA's Central Data Exchange (CDX) at *https://cdx.epa.gov/.* The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as confidential business information (CBI). Anything submitted using CEDRI cannot later be claimed CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim, you must submit a complete file, including the information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA, and the electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same information, with the CBI omitted, must be submitted to the EPA via *r8airreportenforcement@epa.gov* or the EPA's CDX as described earlier in this paragraph. All claims of CBI must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(b) Each owner and operator of an affected oil and natural gas source as identified in § 49.4169(b) must submit an annual report containing the information specified in paragraphs (b)(1) through (3) of this section, as applicable. The annual report must cover affected operations for the previous calendar year. The initial annual report is due April 1st of the calendar year following February 6, 2023 and must cover all affected operations for the previous calendar year on and after February 6, 2023. Subsequent annual reports are due on the same date each year as the date the initial annual report was submitted. If you own or operate more than one oil and natural gas source, you may submit one report for multiple oil and natural gas sources, provided the report contains all of the information required as specified in paragraphs (b)(1) through (3) of this section. Annual reports may coincide with title V, NSPS OOOO or OOOOa, or NESHAP HH reports as long as all the required elements of the annual report are included. An alternative schedule on which the annual report must be submitted will be allowed as long as the schedule does not extend the reporting period. The annual report must include:

(1) The owner or operator name, and the name and location (decimal degree latitude and longitude location indicating the datum used in parentheses) of each oil and natural gas source being included in the annual report.

(2) The beginning and ending dates of the reporting period.

(3) For each oil and natural gas source, a summary of the required records specified in § 49.4183 that are identified in paragraphs (b)(3)(i) through (iv) of this section as they relate to the source's compliance with the requirements of §§ 49.4173 through 49.4183.

(i) For each enclosed combustor or flare at an oil and natural gas source required under §§ 49.4173 through 49.4177:

(A) Records of any instances in which the pilot flame is not present or the monitoring equipment is not functioning, the date and times of the occurrence, the corrective actions taken, and any preventative measures adopted to prevent recurrence of the occurrence; and

(B) Records of any time periods in which visible smoke emissions are observed emanating from the enclosed combustor or flare.

(ii) For each closed-vent system:

(A) Records of any instances in which any closed-vent system or control device was bypassed or down, the reason for each incident, its duration, the corrective actions taken, and any preventative measures adopted to avoid such bypasses or downtimes; and

(B) Records of any instances of defects identified during the monthly inspection required in § 49.4182(c), including:

(*1*) The date of the inspection;

(*2*) The findings of the inspection;

(*3*) Date and description of corrective adjustments or repairs made as a result of the inspection or reason for delay of repair; and

(iii) For Fugitive Emissions Monitoring, records documenting each fugitive emissions inspection, including:

(A) The date of the inspection;

(B) Identification of any component that was determined to be leaking;

(C) Identification of any component designated difficult-to-monitor or unsafe-to-monitor that was not inspected and the reason it was not inspected;

(D) The date of repair of each leaking component;

(E) Identification of any leaking component with a delayed repair, the reason for the delayed repair and the emission estimates associated with any shutdown and repair if the delay is longer than 6 months;

(F) The date and description of any corrective action taken, including the date the component was verified to no longer be leaking;

(G) The inspector's name or identification number;

(H) For each well site complying with § 49.4178(c)(2), you must specify that the well site is exempt from the requirements of § 49.4178(d) and submit the average daily production for the well site; and

(iv) For each pneumatic controller with a natural gas bleed rate greater than the applicable standard, records of the reason for the use of the controller.

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