

EDF'S EXHIBIT VV

**JOINT PROPOSED REVISED AMENDMENTS
TO PROPOSED 20.2.50 NMAC FROM
ENVIRONMENTAL DEFENSE FUND**

AND

**CONSERVATION VOTERS NEW MEXICO,
DINÉ C.A.R.E., EARTHWORKS, NATIONAL
PARKS CONSERVATION ASSOCIATION,
NATURAL RESOURCES DEFENSE
COUNCIL, SAN JUAN CITIZENS ALLIANCE,
SIERRA CLUB, 350 NEW MEXICO, AND 350
SANTA FE**

AND

**CENTER FOR CIVIL POLICY AND NAVA
EDUCATION PROJECT**

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September 7, 2021

**TITLE 20 ENVIRONMENTAL PROTECTION
CHAPTER 2 AIR QUALITY (STATEWIDE)
PART 50 OIL AND GAS SECTOR – OZONE PRECURSOR POLLUTANTS**

20.2.50.1 ISSUING AGENCY: Environmental Improvement Board.
[20.2.50.1 NMAC – N, XX/XX/2021]

20.2.50.2 SCOPE: This Part applies to sources located within areas of the state under the board's jurisdiction that, as of the effective date of this rule or anytime thereafter, are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors. Once a source becomes subject to this rule, the requirements of the rule are irrevocably effective unless the source obtains a federally enforceable air permit limiting the potential to emit to below such applicability thresholds established in this Part.
[20.2.50.2 NMAC – N, XX/XX/2021]

20.2.50.3 STATUTORY AUTHORITY: Environmental Improvement Act, Section 74-1-1 to 74-1-16 NMSA 1978, including specifically Paragraph (4) and (7) of Subsection A of Section 74-1-8 NMSA 1978, and Air Quality Control Act, Sections 74-2-1 to 74-2-22 NMSA 1978, including specifically Subsections A, B, C, D, F, and G of Section 74-2-5 NMSA 1978 (as amended through 2021).
[20.2.50.3 NMAC - N, XX/XX/2021]

20.2.50.4 DURATION: Permanent.
[20.2.50.4 NMAC - N, XX/XX/2021]

20.2.50.5 EFFECTIVE DATE: Month XX, 2021, except where a later date is specified in another Section.
[20.2.50.5 NMAC - N, XX/XX/2021]

20.2.50.6 OBJECTIVE: The objective of this Part is to establish emission standards for volatile organic compounds (VOC) and oxides of nitrogen (NO_x) for oil and gas production, processing, and transmission sources.
[20.2.50.6 NMAC - N, XX/XX/2021]

20.2.50.7 DEFINITIONS: In addition to the terms defined in 20.2.2 NMAC - Definitions, as used in this Part, the following definitions apply.

A. "Approved instrument monitoring method" means an optical gas imaging, United States environmental protection agency (U.S. EPA) reference method 21 (RM21) (40 CFR 60, Appendix B), or other instrument-based monitoring method or program approved by the department in advance and in accordance with 20.2.50 NMAC.

B. "Auto-igniter" means a device that automatically attempts to relight the pilot flame in the combustion chamber of a control device in order to combust VOC emissions, or a device that will automatically attempt to combust the VOC emission stream.

C. "Bleed rate" means the rate in standard cubic feet per hour at which natural gas is continuously or intermittently vented from a pneumatic controller.

D. "Calendar year" means a year beginning January 1 and ending December 31.

E. "Centrifugal compressor" means a machine used for raising the pressure of natural gas by drawing in low-pressure natural gas and discharging significantly higher-pressure natural gas by means of a mechanical rotating vane or impeller. Screw, sliding vane, and liquid ring compressor is not a centrifugal compressor.

F. "Closed vent system" means a system that is designed, operated, and maintained to route the VOC emissions from a source or process to a process stream or control device with no loss of VOC emissions to the atmosphere.

G. "Commencement of operation" means for an oil and natural gas wellhead, the date any permanent production equipment is in use and product is consistently flowing to a sales lines, gathering line or storage vessel from the first producing well at the stationary source, but no later than the end of well completion operation.

H. "Component" means a pump seal, flange, pressure relief device (including thief hatch or other

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opening on a storage vessel), connector or valve that contains or contacts a process stream with hydrocarbons, except for components where process streams consist solely of glycol, amine, produced water or methanol

I. “Connector” means flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, “T’s” or valves) to each other; or a pipe line to a piece of equipment; or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this Part.

J. “Construction” means fabrication, erection, installation or relocation of a stationary source, including but not limited to temporary installations and portable stationary sources.

K. “Custody transfer” means the transfer of oil or natural gas after processing or treatment in the producing operation, or from a storage vessel or automatic transfer facility or other processing or treatment equipment including product loading racks, to a pipeline or any other form of transportation.

L. “Control device” means air pollution control equipment or emission reduction technologies that thermally combust, chemically convert, or otherwise destroy or recover air contaminants. Examples of control devices include but are not limited to open flares, enclosed combustion devices (ECDs), thermal oxidizers (TOs), vapor recovery units (VRUs), fuel cells, condensers, air fuel ratio controllers (AFRs), catalytic converters (oxidative, selective, and non-selective), or other emission reduction equipment. A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department to comply with emission standards in this Part.

M. “Department” means the New Mexico environment department.

N. “Downtime” means the period of time when equipment is not in operation, or when a well is producing, and the control device is not in operation.

O. “Drilling” or “drilled” means the process to bore a hole to create a well for oil and/or natural gas production.

P. “Drill-out” means the process of removing the plugs placed during hydraulic fracturing or refracturing. Drill-out ends after the removal of all stage plugs and the initial wellbore cleanup.

Q. “Enclosed combustion device” means a combustion device where gaseous fuel is combusted in an enclosed chamber. This may include, but is not limited to an enclosed flare, reboiler, and heater.

R. “Existing” means constructed or reconstructed before the effective date of this Part and has not since been modified or reconstructed.

S. “Flowback” means the process of allowing fluids and entrained solids to flow from a well following stimulation, either in preparation for a subsequent phase of treatment or in preparation for cleanup and placing the well into production. The term flowback also means the fluids and entrained solids flowing from a well after drilling or hydraulic fracturing or refracturing. Flowback ends when all temporary flowback equipment is removed from service. Flowback does not include drill-out.

T. “Flowback vessel” means a vessel that contains flowback

U. “Gathering and boosting station” means a permanent combination of equipment that collects or moves natural gas, crude oil, condensate, or produced water between a wellhead site and a midstream oil and natural gas collection or distribution facility, such as a storage vessel battery or compressor station, or into or out of storage.

V. “Hydraulic fracturing” means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale, coal, and tight sand formations, that subsequently require flowback to expel fracture fluids and solids.

W. “Hydraulic refracturing” means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

X. “Glycol dehydrator” means a device in which a liquid glycol absorbent, including ethylene glycol, diethylene glycol, or triethylene glycol, directly contacts a natural gas stream and absorbs water.

Y. “Hydrocarbon liquid” means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, and intermediate hydrocarbons.

Z. “Inactive wellhead site” means a wellhead site where the well is not being used for beneficial purposes, such as production or monitoring, and is not being drilled, completed, repaired or worked over.

AA. “Injection wellhead site” means a wellhead site where the well is used for the injection of air, gas, water or other fluids into an underground stratum.

BB. “Liquid unloading” means the removal of accumulated liquid from the wellbore that reduces or stops natural gas production.

CC. “Liquid transfer” means the loading and unloading of a hydrocarbon liquid or produced water between a storage vessel and tanker truck or tanker rail car for transport.

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DD. “Local distribution company custody transfer station” means a metering station where the local distribution (LDC) company receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

EE. “Natural gas compressor station” means one or more compressors designed to compress natural gas from well pressure to gathering system pressure before the inlet of a natural gas processing plant, or to move compressed natural gas through a transmission pipeline.

FF. “Natural gas-fired heater” means an enclosed device using a controlled flame and with a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

GG. “Natural gas processing plant” means the processing equipment engaged in the extraction of natural gas liquid from natural gas or fractionation of mixed natural gas liquid to a natural gas product, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

HH. “New” means constructed or reconstructed on or after the effective date of this Part.

II. “Occupied area” means (1) a building or structure designed for use as a place of residency by a person, a family, or families. The term includes manufactured, mobile, and modular homes, except to the extent that any such manufactured, mobile, or modular home is intended for temporary occupancy or for business purposes; (2) indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities; (3) five thousand (5,000) or more square feet of building floor area in commercial facilities that are operating and normally occupied during working hours; and (4) an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly.

JJ. “Operator” means the person or persons responsible for the overall operation of a stationary source.

KK. “Optical gas imaging (OGI)” means an imaging technology that utilizes a high-sensitivity infrared camera designed for and capable of detecting hydrocarbons.

LL. “Owner” means the person or persons who own a stationary source or part of a stationary source.

MM. “Permanent pit” means a pit used for collection, retention, or storage of produced water or brine and is installed for longer than one year.

NN. “Pneumatic controller” means an instrument that is actuated using pressurized gas and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow, and temperature.

OO. “Pneumatic diaphragm pump” means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

PP. “Potential to emit (PTE)” means the maximum capacity of a stationary source to emit an air contaminant under its physical and operational design. The physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and a restriction on the hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is federally enforceable. The PTE for nitrogen dioxide shall be based on total oxides of nitrogen.

QQ. “Pre-production operations” means the drilling through the hydrocarbon bearing zones, hydraulic fracturing or refracturing, drill-out, and flowback of an oil and/or natural gas well.

RR. “Produced water” means a fluid that is an incidental byproduct from drilling for or the production of oil and gas.

SS. “Produced water management unit” means a recycling facility or a permanent pit that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 barrels.

TT. “Qualified Professional Engineer” means an individual who is licensed by a state as a professional engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge, and experience to make the specific technical certifications required under this Part.

UU. “Reciprocating compressor” means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of a piston rod.

VV. “Reconstruction” means a modification that results in the replacement of the components or addition of integrally related equipment to an existing source, to such an extent that the fixed capital cost of the new

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components or equipment exceeds fifty percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

WW. “Recycling facility” means a stationary or portable facility used exclusively for the treatment, re-use, or recycling of produced water and does not include oilfield equipment such as separators, heater treaters, and scrubbers in which produced water may be used.

XX. “Responsible official” means one of the following:

(1) for a corporation: president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of the corporation if the representative is responsible for the overall operation of the source.

(2) for a partnership or sole proprietorship: a general partner or the proprietor, respectively.

YY. “Satellite facility” means a liquid storage facility located downstream of primary separation but prior to sales.

ZZ. “Small business facility” means, for the purposes of this Part, a source that is independently owned or operated by a company that is not a subsidiary or a division of another business, that employs no more than 10 employees at any time during the calendar year, and that has a gross annual revenue of less than \$250,000. Employees include part-time, temporary, or limited service workers.

AAA. “Startup” means the setting into operation of air pollution control equipment or process equipment.

BBB. “Stationary Source” or “source” means any building, structure, equipment, facility, installation (including temporary installations), operation, process, or portable stationary source that emits or may emit any air contaminant. Portable stationary source means a source that can be relocated to another operating site with limited dismantling and reassembly.

CCC. “Storage vessel” means a single tank or other vessel that is designed to contain an accumulation of hydrocarbon liquid or produced water and is constructed primarily of non-earthen material including wood, concrete, steel, fiberglass, or plastic, which provide structural support, or a process vessel such as a surge control vessel, bottom receiver, or knockout vessel. A well completion vessel that receives recovered liquid from a well after commencement of operation for a period that exceeds 60 days is considered a storage vessel. A storage vessel does not include a vessel that is skid-mounted or permanently attached to a mobile source and located at the site for less than 180 consecutive days, such as a truck railcar, or a pressure vessel designed to operate in excess of 204.9 kilopascals without emissions to the atmosphere.

DDD. “Temporarily abandoned wellhead site” means an inactive wellhead site where the well’s completion interval has been isolated. The completion interval is the reservoir interval that is open to the borehole and is isolated when tubing and artificial equipment has been removed and a bottom plug has been set.

EEE. “Vessel measurement system” means equipment and methods used to determine the quantity of the liquids inside a vessel (including a flowback vessel) without requiring direct access through the vessel thief hatch or other opening.

FFF. “Well workover” means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons.

GGG. “Wellhead site” means the equipment directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. A wellhead site may include equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping.

[20.2.50.7 NMAC - N, XX/XX/2021]

20.2.50.8 SEVERABILITY: If any provision of this Part, or the application of this provision to any person or circumstance is held invalid, the remainder of this Part, or the application of this provision to any person or circumstance other than those as to which it is held invalid, shall not be affected thereby.

[20.2.50.8 NMAC - N, XX/XX/2021]

20.2.50.9 CONSTRUCTION: This Part shall be liberally construed to carry out its purpose.

[20.2.50.9 NMAC - N, XX/XX/2021]

20.2.50.10 SAVINGS CLAUSE: Repeal or supersession of prior versions of this Part shall not affect administrative or judicial action initiated under those prior versions.

[20.2.50.10 NMAC - N, XX/XX/2021]

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20.2.50.11 COMPLIANCE WITH OTHER REGULATIONS: Compliance with this Part does not relieve a person from the responsibility to comply with other applicable federal, state, or local laws, rules or regulations, including more stringent controls.

[20.2.50.11 NMAC - N, XX/XX/2021]

20.2.50.12 DOCUMENTS: Documents incorporated and cited in this Part may be viewed at the New Mexico environment department, air quality bureau.

[20.2.50.12 NMAC - N, XX/XX/2021]

[The Air Quality Bureau is located at 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico 87505.]

20.2.23.13-20.2.23.110 [RESERVED]

20.2.50.111 APPLICABILITY:

A. This Part applies to crude oil and natural gas production and processing equipment and operations that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquid or produced water in the areas specified in 20.2.50.2 NMAC and are located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations, up to the point of the local distribution company custody transfer station.

B. In determining if any source is subject to this Part, including a small business facility as defined in this Part, the owner or operator shall calculate the Potential to Emit (PTE) of such source and shall have the PTE calculation certified by a qualified professional engineer or in-house engineer with expertise regarding the calculation of PTE. The calculation shall be kept on file for a minimum of five years and shall be provided to the department upon request.

C. An owner or operator of a small business facility as defined in this Part shall comply with the requirements of this Part as specified in 20.2.50.125 NMAC.

D. Oil refinery and transmission pipelines are not subject to this Part.

[20.2.50.111 NMAC - N, XX/XX/2021]

20.2.50.112 GENERAL PROVISIONS:

A. General requirements:

(1) Sources subject to emissions standards and requirements under this Part shall be operated and maintained consistent with manufacturer specifications, and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available upon request by the department. For sources constructed prior to 1980 for which no manufacturer specifications and maintenance practices are available, the owner or operator shall develop and follow a maintenance schedule sufficient to operate and maintain such units in good working order. The owner or operator shall keep such maintenance schedules on file and make them available to the department upon request.

(2) Sources subject to emission standards or requirements under this Part shall be operated to minimize emissions of air contaminants, including VOC and NO_x.

(3) The owner or operator shall manage the source's record of data in a database that is able to generate a Compliance Database Report (CDR) adequate to provide the department with compliance assurance. The CDR is an electronic report generated by the owner or operator's database and submitted to the department upon request. The format of the CDR shall be determined by the department.

(4) The CDR is a report distinct from the owner or operator's database. The department does not require access to the owner or operator's database, only the CDR.

(5) If read by the owner or operator's authorized representative, the Equipment Monitoring Tags (EMT) for sources that utilize EMT shall access the owner or operator's database record for that source.

(3)(6) The owner or operator shall contemporaneously track each compliance event for each source subject to the requirements of this Part, and shall comply with the following:

(a) data gathered during each monitoring or testing event shall be contemporaneously uploaded into the database as soon as practicable, but no later than three business days of each compliance event.

(b) data required by this Part shall be maintained in the database for at least five years.

(73) Within two years of the effective date of this Part, owners and operators of a source

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utilizing an ~~requiring an Equipment Monitoring Tag (EMT) system for compliance assurance~~ shall physically tag each unit with an EMT, the format of which shall be either RFID, QR, or bar code such that, when scanned it provides a unique identifier of the source. This unique identifier shall act as an index to the source's record of the data required by this Part. The EMT shall be maintained by the owner or operator, and data in the EMT shall provide at a minimum, the following information:

- (a) unique unit identification number;
- (b) location of the source;
- (c) type of source (e.g., tank, VRU, dehydrator, pneumatic controller, etc.);
- (d) for each source, the VOC (and NO_x, if applicable) PTE in lbs./hr. and tpy;
- (e) for a control device, the controlled VOC and NO_x PTE in lbs./hr. and tpy;
- (f) make, model, and serial number; and
- (g) a link to the manufacturer's maintenance schedule or repair recommendations.

~~(84)~~ The EMT shall be installed and maintained by the owner or operator of the facility.

~~(95)~~ The EMT shall be of a format scannable by an owner or operator's authorized representatives and, upon scanning, shall provide unique identifier that shall index the source's record of the data required by this Part.

~~(6) The owner or operator shall manage the source's record of data in a database that is able to generate a Compliance Database Report (CDR). The CDR is an electronic report generated by the owner or operator's database and submitted to the department upon request. The format of the CDR shall be determined by the department.~~

~~(7) The CDR is a report distinct from the owner or operator's database. The department does not require access to the owner or operator's database, only the CDR.~~

~~(8) If read by the owner or operator's authorized representative, the EMT shall access the owner or operator's database record for that source.~~

~~(9) The owner or operator shall contemporaneously track each compliance event for each source subject to the EMT requirements of this Part, and shall comply with the following:~~

~~(a) data gathered during each monitoring or testing event shall be contemporaneously uploaded into the database as soon as practicable, but no later than three business days of each compliance event.~~

~~(b) data required by this Part shall be maintained in the database for at least five years.~~

(10) The department may request that an owner or operator retain a third party at their own expense to verify any data or information collected, reported, or recorded pursuant to this Part, and make recommendations to correct or improve the collection of data or information. The owner or operator shall submit a report of the verification and any recommendations made by the third party to the department by a date specified and implement the recommendations in the manner approved by the department.

B. Monitoring requirements:

(1) Sources subject to emission standards and monitoring (e.g. inspection, testing, parametric monitoring) requirements under this Part shall be inspected monthly to ensure proper maintenance and operation, unless a different schedule is specified in the Section applicable to that source type. If the equipment is shut down at the time of required periodic testing, monitoring, or inspection, the owner or operator shall not be required to restart the unit for the sole purpose of performing the testing, monitoring, or inspection, but shall note the shut down in the records kept for that equipment for that monitoring event.

(2) An owner or operator may submit for the department's review and approval an equally effective, enforceable, and equivalent alternative monitoring strategy. Such requests shall be made on an application form provided by the department. The department shall issue a letter approving or denying the requested alternative monitoring strategy. An owner or operator shall comply with the default monitoring requirements required under the applicable Section and shall not operate under an alternative monitoring strategy until it has been approved by the department.

(a) For sources that implement alternative monitoring strategies, initial scanning of the EMT before a monitoring event and final scanning of an EMT at the end of the monitoring event are not required provided that electronic data retrieved from the monitoring event satisfies the requirements found at 20.2.50.112(B)(3)(a)-(e) NMAC and is uploaded to the owner or operator's database following the monitoring event.

(3) Each For sources that utilize an EMT, each -monitoring event (e.g. testing, inspection, parametric monitoring) shall be initiated by an initial scanning of the EMT, the results of which shall then be

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directly uploaded into the database or temporarily into the handheld or other device. Upon completion of the monitoring event, a final scanning of the EMT shall terminate the monitoring event. At a minimum, the uploaded data shall include:

- (a) date and time of the testing, monitoring, or inspection event;
- (b) name of the personnel conducting the testing, monitoring, or inspection;
- (c) identification number and type of unit;
- (d) a description of any maintenance or repair activity conducted; and
- (e) results of testing, monitoring, or inspection as required under this Part.

C. Recordkeeping requirements:

(1) Within three business days of a monitoring event, an electronic record shall be made of the monitoring event and shall include the following data:

- (a) date and time of the testing, monitoring, or inspection event;
- (b) name of the personnel conducting the testing, monitoring, or inspection;
- (c) identification number and type of unit;
- (d) a description of any maintenance or repair activity conducted; and
- (e) results of any testing, monitoring, or inspections required under this Part.

(2) The owner or operator shall keep an electronic record required by this Part for five years. The department may treat loss of data or failure to maintain a record, including failure to transfer a record upon sale or transfer of ownership or operating authority, as a failure to collect the data.

~~(3) Before the transfer of ownership of equipment subject to this Part, the current owner or operator shall conduct and document a full compliance evaluation of such equipment. The documentation shall include a certification by a responsible official as to whether the equipment is in compliance with the requirements of this Part. The compliance determination shall be conducted no earlier than three months before the transfer of ownership. The owner or operator shall keep the full compliance evaluation and certification by the responsible official for for five years.~~

D. Reporting requirements: Within 24 hours of a request by the department, the owner or operator shall for each unit subject to the request, provide the requested information either by electronically submitting a CDR to the department's Secure Extranet Portal (SEP), or by other means and formats specified by the department in its request.

[20.2.50.112 NMAC - N, XX/XX/2021]

20.2.50.113 ENGINES AND TURBINES:

A. Applicability: Portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations, with a rated horsepower greater than the horsepower ratings of Table 1, 2, and 3 of 20.2.50.113 NMAC are subject to the requirements of 20.2.50.113 NMAC.

B. Emission standards:

(1) The owner or operator of a portable or stationary natural gas-fired spark-ignition engine, compression ignition engine, or natural gas-fired combustion turbine shall ensure compliance with the emission standards by the dates specified in Subsection B of 20.2.50.113 NMAC.

(2) The owner or operator of an existing natural gas-fired spark-ignition engine shall complete an inventory of all existing engines by January 1, 2023, and shall prepare a schedule to ensure that each existing engine does not exceed the emission standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC as follows:

- (a) by January 1, 2025, the owner or operator shall ensure at least thirty percent of the company's existing engines meet the emission standards.
- (b) by January 1, 2027, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing engines meets the emission standards.
- (c) by January 1, 2029, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing engines meets the emission standards.
- (d) in lieu of meeting the emission standards for an existing natural gas-fired spark ignition engine, an owner or operator may reduce the annual hours of operation of an engine such that the annual NOx and VOC emissions are reduced by at least ninety-five percent per year.

Table 1 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES

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Engine Type	Rated bhp	NO _x	CO	NMNEHC (as propane)
Lean-burn	>1,000	0.50 g/bhp-hr	47 ppmvd @ 15% O ₂ or 93% reduction	0.70 g/bhp-hr
Rich-burn	>1,000	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

(3) The owner or operator of a new natural gas-fired spark ignition engine shall ensure the engine does not exceed the emission standards in table 2 of Paragraph (3) of Subsection B of 20.2.50.113 NMAC upon startup.

Table 2 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES
CONSTRUCTED, RECONSTRUCTED, OR INSTALLED AFTER THE EFFECTIVE DATE OF 20.2.50 NMAC.

Engine Type	Rated bhp	NO _x	CO	NMNEHC (as propane)
Lean-burn	>500 - <1,000	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Lean-burn	≥1,000	0.30 g/bhp-hr uncontrolled or 0.05 g/bhp-hr with control	0.60 g/bhp-hr	0.70 g/bhp-hr
Rich-burn	>500	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

(4) The owner or operator of a natural gas-fired spark ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(5) The owner or operator of a compression ignition engine shall ensure compliance with the following emission standards:

(a) a new portable or stationary compression ignition engine with a maximum design power output equal to or greater than 500 horsepower that is not subject to the emission standards under Subparagraph (b) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC shall limit NO_x emissions to not more than nine g/bhp-hr upon startup.

(b) a stationary compression ignition engine that is subject to and complying with Subpart III of 40 CFR Part 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, is not subject to the requirements of Subparagraph (a) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC.

(6) The owner or operator of a portable or stationary compression ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(7) The owner or operator of a stationary natural gas-fired combustion turbine with a maximum design rating equal to or greater than 1,000 bhp shall comply with the applicable emission standards for an existing, new, or reconstructed turbine listed in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC.

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

For each natural gas-fired combustion turbine constructed or reconstructed and installed before the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than two years from the effective date of this Part:			
Turbine Rating (bhp)	NO _x (ppmvd @15% O ₂)	CO (ppmvd @ 15% O ₂)	NMNEHC (as propane, ppmvd @15% O ₂)
≥1,000 and <5,000	50	50	9
≥5,000 and <15,000	50	50	9
≥15,000	50	50 or 93% reduction	5 or 50% reduction

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For each natural gas-fired combustion turbine constructed or reconstructed and installed on or after the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards upon startup:			
Turbine Rating (bhp)	NO _x (ppmvd @15% O ₂)	CO (ppmvd @ 15% O ₂)	NMNEHC (as propane, ppmvd @15% O ₂)
≥1,000 and <5,000	25	25	9
≥5,000 and <15,900	15	10	9
≥15,900	9.0 Uncontrolled or 2.0 with Control	10 Uncontrolled or 1.8 with Control	5

(8) The owner or operator of a stationary natural gas-fired combustion turbine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(9) The owner or operator of an engine or turbine shall install an EMT on the engine or turbine in accordance with 20.2.50.112 NMAC.

(10) The owner or operator of an emergency use engine that is operated less than 100 hours per year is not subject to the emissions standards in this Part but shall be equipped with a non-resettable hour meter to monitor and record any hours of operation.

C. Monitoring requirements:

(1) Maintenance and repair for a spark-ignition engine, compression-ignition engine, and stationary combustion turbine shall meet the minimum manufacturer recommended maintenance schedule. The following maintenance, adjustment, replacement, or repair events for engines and turbines shall be documented as they occur:

(a) routine maintenance that takes a unit out of service for more than two hours during any 24-hour period; and

(b) unscheduled repairs that require a unit to be taken out of service for more than two hours during any 24-hour period.

(2) Catalytic converters (oxidative, selective and non-selective) and AFR controllers shall be maintained according to manufacturer or supplier recommended maintenance schedules, including replacement of oxygen sensors as necessary for oxygen-based controllers. During periods of catalytic converter or AFR controller maintenance, the owner or operator shall shut down the engine or turbine until the catalytic converter or AFR controller can be replaced with a functionally equivalent spare to allow the engine or turbine to return to operation.

(3) For equipment operated for 500 hours per year or more, compliance with the emission standards in Subsection B of 20.2.50.113 NMAC shall be demonstrated by performing an initial emissions test, followed by annual tests, for NO_x, CO, and non-methane non-ethane hydrocarbons (NMNEHC) using a portable analyzer or U.S. EPA reference method. For units with g/hp-hr emission standards, the engine load shall be calculated using the following equations:

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (scf/hr)} \times \text{Measured fuel heating value (LHV btu/scf)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (gal/hr)} \times \text{Measured fuel heating value (LHV btu/gal)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

Where: LVH = lower heating value, btu/scf, or btu/gal, as appropriate; and

BSFC = brake specific fuel consumption

(a) emissions testing events shall be conducted at ninety percent or greater of the unit's capacity. If the ninety percent capacity cannot be achieved, the monitoring and testing shall be conducted at the maximum achievable capacity or load under prevailing operating conditions. The load and the parameters used to calculate it shall be recorded to document operating conditions at the time of testing and shall be included with the test report.

(b) emissions testing utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D 6522. If a portable analyzer has met a previously approved department criterion, the analyzer may be operated in accordance with that criterion until it is replaced.

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- 1 (c) the default time period for a test run shall be at least 20 minutes.
- 2 (d) an emissions test shall consist of three separate runs, with the arithmetic mean of
- 3 the results from the three runs used to determine compliance with the applicable emission standard.
- 4 (e) during emissions tests, pollutant and diluent concentration shall be monitored
- 5 and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing U.S. EPA
- 6 reference method 19. This information shall be included with the periodic test report.
- 7 (f) stack gas flow rate shall be calculated in accordance with U.S. EPA reference
- 8 method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (Btu/scf).
- 9 The owner or operator shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no
- 10 earlier than three months before the test date) and a recent fuel flow meter calibration certificate (within the most
- 11 recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using U.S. EPA
- 12 reference methods 1 through 4 or through the use of manufacturer provided fuel consumption rates.
- 13 (g) upon request by the department, an owner or operator shall submit a notification
- 14 and protocol for an initial or annual emissions test.
- 15 (h) emissions testing shall be conducted at least once per calendar year. Emission
- 16 testing required by Subparts GG, IIII, JJJJ, or KKKK of 40 CFR 60, or Subpart ZZZZ of 40 CFR 63, may be used to
- 17 satisfy the emissions testing requirements if it meets the requirements of 20.2.50.113 NMAC and is completed at
- 18 least once per calendar year.
- 19 (4) The owner or operator of equipment operated less than 500 hours per year shall monitor
- 20 the hours of operation using a non-resettable hour meter and shall test the unit at least once per 8760 hours of
- 21 operation in accordance with the emissions testing requirements in Paragraph (3) of Subsection C of 20.2.50.113
- 22 NMAC.
- 23 (5) An owner or operator of an emergency use engine operated for less than 100 hours per
- 24 year shall monitor the hours of operation by a non-resettable hour meter.
- 25 (6) An owner or operator limiting the annual operating hours of an engine to meet the
- 26 requirements of Paragraph (2) of Subsection B of 20.2.50.113 NMAC shall monitor the hours of operation by a non-
- 27 resettable hour meter.
- 28 (7) Prior to monitoring, testing, inspection, or maintenance of an engine or turbine, the owner
- 29 or operator shall scan the EMT, and the monitoring data entry shall be made in accordance with the requirements of
- 30 20.2.50.112 NMAC.
- 31 **D. Recordkeeping requirements:**
- 32 (1) The owner or operator of a spark ignition engine, compression ignition engine, or
- 33 stationary combustion turbine shall maintain a record in accordance with 20.2.50.112 NMAC for the engine or
- 34 turbine. The record shall include:
- 35 (a) the make, model, serial number, and EMT for the engine or turbine;
- 36 (b) a copy of the engine, turbine, or control device manufacturer recommended
- 37 maintenance and repair schedule;
- 38 (c) all inspection, maintenance, or repair activity on the engine, turbine, and control
- 39 device, including:
- 40 (i) the date and time of an inspection, maintenance or repair;
- 41 (ii) the date a subsequent analysis was performed (if applicable);
- 42 (iii) the name of the personnel conducting the inspection, maintenance or
- 43 repair;
- 44 (iv) a description of the physical condition of the equipment as found
- 45 during the inspection;
- 46 (v) a description of maintenance or repair activity conducted; and
- 47 (vi) the results of the inspection and any required corrective actions.
- 48 (2) The owner or operator of a spark ignition engine, compression ignition engine, or
- 49 stationary combustion turbine shall maintain records of initial and annual emissions testing for the engine or turbine.
- 50 The records shall include:
- 51 (a) the make, model, serial number, and EMT for the tested engine or turbine;
- 52 (b) the date and time of sampling or measurements;
- 53 (c) the date analyses were performed;
- 54 (d) the name of the personnel and the qualified entity that performed the analyses;
- 55 (e) the analytical or test methods used;
- 56 (f) the results of analyses or tests;

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(g) for equipment operated less than 500 hours per year, the total annual hours of operation as recorded by the non-resettable hour meter; and

(h) operating conditions at the time of sampling or measurement.

(3) The owner or operator of an emergency use engine operated less than 100 hours per year shall record the total annual hours of operation as recorded by the non-resettable hour meter.

(4) The owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) of Subsection B of 20.2.50.113 NMAC shall record the hours of operation by a non-resettable hour meter. The owner or operator shall calculate and record the annual NO_x and VOC emission calculation, based on the engine's actual hours of operation, to demonstrate the ninety-five percent emission reduction requirement is met.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.113 NM-C - N, XX/XX/2021]

20.2.50.114 COMPRESSOR SEALS:

A. Applicability:

(1) Centrifugal compressors using wet seals and located at tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.114 NMAC. Centrifugal compressors located at wellhead sites are not subject to the requirements of 20.2.50.114 NMAC.

(2) Reciprocating compressors located at tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.114 NMAC. Reciprocating compressors located at wellhead sites are not subject to the requirements of 20.2.50.114 NMAC.

B. Emission standards:

(1) The owner or operator of an existing centrifugal compressor shall control VOC emissions from a centrifugal compressor wet seal fluid degassing system by at least ninety-five percent within two years of the effective date of this Part. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(2) The owner or operator of an existing reciprocating compressor shall, either:
(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation or every 36 months, whichever is reached later. The owner or operator shall begin counting the hours of compressor operation toward the first replacement of the rod packing upon the effective date of this Part; or

(b) beginning no later than two years from the effective date of this Part, collect emissions from the rod packing under negative pressure and route them via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(3) The owner or operator of a new centrifugal compressor shall control VOC emissions from the centrifugal compressor wet seal fluid degassing system by at least ninety-eight percent upon startup. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a new reciprocating compressor shall, upon startup, either:

(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation, or every 36 months, whichever is reached later; or

(b) collect emissions from the rod packing under negative pressure and route them via a closed vent system to a control device, a recovery system, fuel cell or a process stream.

(5) The owner or operator of a centrifugal or reciprocating compressor shall install an EMT on the compressor in accordance with 20.2.50.112 NMAC.

(6) The owner or operator complying with the emission standards in Subsection B of 20.2.50.114 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of a centrifugal compressor complying with Paragraph (1) or (3) of Subsection B of 20.2.50.114 NMAC shall maintain a closed vent system encompassing the wet seal fluid degassing system that complies with the monitoring requirements in 20.2.50.115 NMAC.

(2) The owner or operator of a reciprocating compressor complying with Subparagraph (a) of Paragraph (2) or Subparagraph (a) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall continuously

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monitor the hours of operation with a non-resettable hour meter and track the number of hours since initial startup or since the previous reciprocating compressor rod packing replacement.

(3) The owner or operator of a reciprocating compressor complying with Subparagraph (b) of Paragraph (2) or Subparagraph (b) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall monitor the rod packing emissions collection system semiannually to ensure that it operates under negative pressure and routes emissions through a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a closed vent system or control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(5) The owner or operator of a centrifugal or reciprocating compressor shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a centrifugal compressor using a wet seal fluid degassing system shall maintain a record of the following:

(a) the location of the centrifugal compressor;

(b) the date of construction, reconstruction, or modification of the centrifugal compressor;

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including the time and date of the monitoring, the personnel conducting the monitoring, a description of any problem observed during the monitoring, and a description of any corrective action taken; and

(d) the type, make, model, and identification number of a control device used to comply with the control requirements in Subsection B of 20.2.50.114 NMAC.

(2) The owner or operator of a reciprocating compressor shall maintain a record of the following:

(a) the location of the reciprocating compressor;

(b) the date of construction, reconstruction, or modification of the reciprocating compressor; and

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including:

(i) the number of hours of operation since initial startup or the last rod packing replacement;

(ii) the records of pressure in the rod packing emissions collection system; and

(iii) the time and date of the inspection, the personnel conducting the inspection, a notation of which checks required in Subsection C of 20.2.50.114 NMAC were completed, a description of problems observed during the inspection, and a description and date of corrective actions taken.

(3) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a control device or closed vent system shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(4) The owner or operator of a centrifugal or reciprocating compressor shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator of a centrifugal or reciprocating compressor shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.114 NM-C - N, XX/XX/2021]

20.2.50.115 CONTROL DEVICES:

A. Applicability: These requirements apply to control devices as defined in 20.2.50.7 NMAC and used to comply with the emission standards and emission reduction requirements in this Part.

B. General requirements:

(1) Control devices used to demonstrate compliance with this Part shall be installed, operated, and maintained consistent with manufacturer specifications, and good engineering and maintenance practices.

(2) Control devices shall be adequately designed and sized to achieve the control efficiency rates required by this Part and to handle fluctuations in emissions of VOC or NO_x.

(3) The owner or operator of a control device used to comply with the emission standards in this Part shall install an EMT on the control device in accordance with 20.2.50.112 NMAC.

(4) The owner or operator shall inspect control devices used to comply with this Part at least

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monthly to ensure proper maintenance and operation. Prior to an inspection or monitoring event, the owner or operator shall scan the EMT and the required monitoring data shall be electronically captured in accordance with this Part.

(5) The owner or operator shall ensure that a control device used to comply with emission standards in this Part operates as a closed vent system that captures and routes VOC emissions to the control device, and that unburnt gas is not directly vented to the atmosphere.

(6) The owner or operator of a closed vent system for a centrifugal compressor wet seal fluid degassing system, reciprocating compressor, pneumatic controller or pump, ~~or~~ storage vessel, or flowback vessel using a control device or routing emissions to a process shall:

(a) ensure the control device or process is of sufficient design and capacity to accommodate all emissions from the affected sources;

(b) conduct an assessment to confirm that the closed vent system is of sufficient design and capacity to ensure that all emissions from the affected equipment are routed to the control device or process; and

(c) have the closed vent system certified by a qualified professional engineer or an in-house engineer with expertise regarding the design and operation of the closed vent system in accordance with Paragraphs (c)(i) and (ii) of this Section.

(i) The assessment of the closed vent system shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in Paragraph (c)(ii) of this Section.

(ii) the owner or operator shall provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted, and this report was prepared pursuant to the requirements of this Part. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(7) The owner or operator shall keep manufacturer specifications for all control devices on file. The information shall include:

(a) manufacturer name, make, and model;

(b) maximum heating value for an open flare, ECD, or TO;

(c) maximum rated capacity for an open flare, ECD/TO, or VRU;

(d) gas flow range for an open flare, ECD, or TO; and

(e) designed destruction or vapor recovery efficiency.

C. Requirements for open flares:

(1) Emission standards:

(a) the flare shall combust the gas sent to the flare and combustion shall be maintained for the duration of time that gas is sent to the flare. The owner or operator shall not send gas to the flare in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip each new and existing flare (except those flares required to meet the requirements of Paragraph (C) of this Subsection) with a continuous pilot flame, an operational auto-igniter, or require manual ignition, and shall comply with the following:

(i) a flare with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure the flare is operated with a flame present at all times when gas is being sent to the flare.

(ii) the owner or operator of a flare with manual ignition shall inspect and ensure a flame is present upon initiating a flaring event.

(iii) a new flare controlling a continuous gas stream shall be equipped with a continuous pilot flame upon startup.

(iv) an existing flare controlling a continuous gas stream constructed before the effective date of this Part shall be equipped with a continuous pilot no later than one year after the effective date of this Part.

(c) an existing flare located at a site with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of 60,000 standard cubic feet of natural gas shall be equipped with an auto-ignitor, continuous pilot, or technology (e.g. alarm) that alerts the owner or operator of a flare malfunction, if replaced or reconstructed after the effective date of this Part.

(d) the owner or operator shall operate a flare with no visible emissions, except for

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periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The flare shall be designed so that an observer can, by means of visual observation from the outside of the flare or by other means such as a continuous monitoring device, determine whether it is operating properly.

(e) the owner or operator shall repair the flare within three business days of any alarm activation.

(2) Monitoring requirements:

(a) the owner or operator of a flare with a continuous pilot or auto igniter shall continuously monitor the presence of a pilot flame, or presence of flame during flaring if using an auto igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department;

(b) the owner or operator of a manually ignited flare shall monitor the presence of a flame using continuous visual observation during a flaring event;

(c) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the flare pilot or auto igniter flame is present to certify compliance with visible emission requirements. The observation period shall be a minimum of 15 consecutive minutes;

(d) prior to an inspection or monitoring event, the EMT on the flare shall be scanned and the required monitoring data shall be electronically captured during the event in accordance with the monitoring requirements of 20.2.50.112 NMAC; and

(e) the owner or operator shall monitor the technology that alerts the owner or operator of a flare malfunction and any instances of technology or alarm activation.

(3) Recordkeeping requirements: The owner or operator of an open flare shall keep a record of the following:

(a) any instance of alarm activation, including the date and cause of alarm activation, action taken to bring the flare into a normal operating condition, the name of the personnel conducting the inspection, and any maintenance activity performed;

(b) the results of the U.S. EPA method 22 observations;

(c) the monitoring of the presence of a flame on a manual flare during a flaring event as required under Subparagraph (b) of Paragraph (2) of Subsection C of 20.2.50.115 NMAC;

(d) the results of the gas analysis for the gas being flared, including VOC content and heating value; and

(e) any instance of technology or alarm activation of a malfunctioning flare, including the date and cause of the activation, the action taken to bring the flare into normal operating condition, date of repair, name of the personnel conducting the inspection, and any maintenance activities performed.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

D. Requirements for enclosed combustion devices (ECD) and thermal oxidizers (TO):

(1) Emission standards:

(a) the ECD/TO shall combust the gas sent to the ECD/TO. The owner or operator shall not send gas to the ECD/TO in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip an ECD/TO with a continuous pilot flame or an auto-igniter. Existing ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter no later than one year after the effective date. New ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter upon startup.

(c) ECD/TO with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure that the ECD/TO is operated with a flame present at all times when gas is sent to the ECD/TO. Combustion shall be maintained for the duration of time that gas is sent to the ECD/TO.

(d) the owner or operator shall operate an ECD/TO with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The ECD/TO shall be designed so that an observer can, by means of visual observation from the outside of the ECD/TO or by other means such as a continuous monitoring device, determine whether it is operating properly.

(2) Monitoring requirements:

(a) the owner or operator of an ECD/TO with a continuous pilot or an auto igniter shall continuously monitor the presence of a pilot flame, or of a flame during combustion if using an auto-igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An

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alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department.

(b) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the ECD/TO pilot flame or auto igniter flame is present to certify compliance with the visible emission requirements. The period of observation shall be a minimum of 15 consecutive minutes.

(c) prior to an inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.112 NMAC.

(3) Recordkeeping requirements: The owner or operator of an ECD/TO shall keep records of the following:

(a) any instance of an alarm activation, including the date and cause of the activation, any action taken to bring the ECD/TO into normal operating condition, the name of the personnel conducting the inspection, and any maintenance activities performed;

(b) the result of the U.S. EPA method 22 observation; and

(c) the results of gas analysis for the gas being combusted, including VOC content and heating value.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

E. Requirements for vapor recover units (VRU):

(1) Emission standards:

(a) the owner or operator shall operate the VRU as a closed vent system that captures and routes all VOC emissions directly back to the process or to a sales pipeline and does not vent to the atmosphere.

(b) the owner or operator shall control VOC emissions during startup, shutdown, maintenance, or other VRU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRU.

(2) Monitoring Requirements:

(a) the owner or operator shall comply with the standards for equipment leaks in 20.2.50.116 NMAC, or, alternatively, shall implement a program that meets the requirements of Subpart OOOOa of 40 CFR 60.

(b) prior to a VRU inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.112 NMAC.

(3) Recordkeeping requirements: For a VRU inspection or monitoring event, the owner or operator shall record the result of the event in accordance with 20.2.50.112 NMAC, including the name of the personnel conducting the inspection, and any maintenance or repair activities required. The owner or operator shall record the type of redundant control device used during VRU downtime.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

F. Recordkeeping requirements: The owner or operator of a control device shall maintain a record of the following:

(1) the certification of the closed vent system as required by this Part; and

(2) the information required in Paragraph (7) of Subsection B of 20.2.50.115 NMAC.

G. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

~~H. Requirements for flowback vessels and preproduction operations:~~

~~(1) Emissions standards:~~

~~(a) the owner or operator of a well that begins flowback on or after [effective date of this Part] must collect and control emissions from each flowback vessel on and after the date flowback is routed to the flowback vessel by routing emissions to an operating control device that achieves a hydrocarbon control efficiency of at least 95 percent. If a TO or ECD is used, it must have a design destruction efficiency of at least 98 percent for hydrocarbons.~~

~~(i) the owner or operator shall use enclosed, vapor tight flowback vessels with an appropriate pressure relief system to be used only as necessary to ensure safety.~~

~~(ii) flowback vessels must be inspected, tested, and refurbished where necessary to ensure the flowback vessel is vapor tight prior to receiving flowback~~

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~~(iii) the owner or operator shall use a tank measurement system to determine the quantity of liquids in the flowback vessel(s);~~
~~(A) Thief hatches or other access points to the flowback vessel must remain closed and latched during activities to determine the quantity of liquids in the flowback vessel(s);~~
~~(B) Opening the thief hatch or other access point if required to inspect, test, or calibrate the tank measurement system or to add biocides or chemicals is not a violation of Section 115.H(1)(iv)(i);~~
~~(2) Monitoring~~
~~(a) Owners and or operators of a well with flowback that begins on or after the effective date of 20.2.50 NMAC, must conduct daily visual inspections of the flowback vessel and any associated equipment, including~~
~~(i) visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly seated;~~
~~(ii) visual inspection or monitoring of the control device to ensure that it is operating;~~
~~(iii) visual inspection of the control device to ensure that the valves for the piping from the flowback vessel to the control device are open;~~
~~(3) Recordkeeping~~
~~(a) The owner or operator of each flowback vessel subject to Section 115.H(1), must maintain records for a period of five (5) years and make them available to the NMED upon request, including~~
~~(i) the API number of the well and the associated facility location, including latitude and longitude coordinates;~~
~~(ii) the date and time of the onset of flowback;~~
~~(iii) the date and time the flowback vessels were permanently disconnected, if applicable;~~
~~(iv) the date and duration of any period where the control device is not operating;~~
~~(v) records of the inspections required in Section 115.H(2), including the time and date of each inspection, a description of any problems observed, a description and date of any corrective action(s) taken, and the name of the employee or third party performing corrective action(s);~~
[20.2.50.115 NM-C - N, XX/XX/2021]

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:

A. Applicability: Wellhead sites, tank batteries, gathering and boosting sites, gas processing plants, transmission compressor stations, and associated piping and components are subject to the requirements of 20.2.50.116 NMAC.

B. Emission standards: The owner or operator of oil and gas production and processing equipment located at wellhead sites, tank batteries, gathering and boosting sites, gas processing plants, or transmission compressor stations shall demonstrate compliance with this Part by performing the monitoring, recordkeeping, and reporting requirements specified in 20.2.50.116 NMAC.

C. Default Monitoring requirements: Owners and operators shall comply with the following monitoring requirements and the monitoring requirements in 20.2.50.112 NMAC:

(1) The owner or operator of a facility with an annual average daily production of greater than 10 barrels of oil per day or an average daily production of greater than 60,000 standard cubic feet per day of natural gas shall, at least weekly, conduct audio, visual, and olfactory (AVO) inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components as follows:

(a) conduct a visual inspection for: cracks, holes, or gaps in piping or covers; loose connections; liquid leaks; broken or missing caps; broken, cracked or otherwise damaged seals or gaskets; broken or missing hatches; or broken or open access covers or other closure or bypass devices;
(b) conduct an audio inspection for pressure leaks and liquid leaks;
(c) conduct an olfactory inspection for unusual or strong odors;
(d) any positive detection during the AVO inspection shall be considered a leak; and
(e) a leak discovered by an AVO inspection shall be tagged with a visible tag and reported to management or their designee within three calendar days.

(2) The owner or operator of a facility with an annual average daily production of equal to or

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less than 10 barrels of oil per day or an average daily production of equal to or less than 60,000 standard cubic feet per day of natural gas shall, at least monthly, conduct an audio, visual, and olfactory (AVO) inspection of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify a defect and leaking component as specified in Subparagraphs (a) through (e) of Paragraph (1) of Subsection (C) of 20.2.50.116 NMAC.

(3) The owner or operator of the following facilities shall conduct an inspection using U.S. EPA method 21 or optical gas imaging (OGI) of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify leaking components at a frequency determined according to the following schedules:

(a) for wellhead sites or tank battery facilities:
 (i) annually at facilities with a PTE less than two tpy VOC;
 (ii) semi-annually at facilities with a PTE equal to or greater than two tpy and less than five tpy VOC; and
 (iii) quarterly at facilities with a PTE equal to or greater than five tpy VOC.
 (b) for gathering and boosting sites, gas processing plants, and transmission compressor stations:

(i) quarterly at facilities with a PTE less than 25 tpy VOC; and
 (ii) monthly at facilities with a PTE equal to or greater than 25 tpy VOC.

(c) for wellhead sites within 1,000 feet of an occupied area:
 (i) quarterly at facilities with a PTE less than 5 tpy VOC; and
 (ii) monthly at facilities with a PTE equal to or greater than 5 tpy VOC.

(4) Inspections using U.S. EPA method 21 shall meet the following requirements:

(a) the instrument shall be calibrated before each day of its use by the procedures specified in U.S. EPA method 21;

(b) the instrument shall be calibrated with zero air (less than 10 ppm of hydrocarbon in air), and a mixture of methane or n-hexane and air at a concentration near, but not more than, 10,000 ppm methane or n-hexane; and

(c) a leak is detected if the instrument records a measurement of 500 ppm or greater of hydrocarbon and the measurement is not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

(5) Inspections using OGI shall meet the following requirements:

(a) the instrument shall comply with the specifications, daily instrument checks, and leak survey requirements set forth in Subparagraphs (1) through (3) of Paragraph (i) of 40 CFR 60.18;

(b) a leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation, such as pneumatic device actuation or crank case ventilation.

(6) Components that are difficult, unsafe, or inaccessible to monitor, as determined by the following conditions, are not required to be inspected until it becomes feasible to do so:

(a) difficult to monitor components are those that require elevating the monitoring personnel more than two meters above a supported surface, or that cannot be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to seven and six tenths meters (25 feet) above the ground;

(b) unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring; and

(c) inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

(7) Owners and operators with wellhead sites subject to the requirements contained in Subparagraph (c) of Paragraph (3) of Subsection (C) of 20.2.50.116 NMAC must conduct an evaluation to determine applicability within 30 days of constructing a new wellhead site and annually within 90 days of the effective date of this Part for existing wellhead sites. Homeowners may contact NMED to request an owner or operator conduct the evaluation required by this Part.

(8) The leak survey requirements of Paragraphs (3) to (6) of Subsection (C) of 20.2.50.116 NMAC shall not apply to facilities where leak surveys are not anticipated to result in emissions reductions. Such facilities include satellite facilities, injection wellhead sites, and temporarily abandoned wellhead sites.

(9) The owner or operator of a wellhead site that becomes an inactive wellhead site after the effective date of this Part must complete the next inspection required under Paragraph (3) of Subsection (C) of 20.2.50.116 NMAC no sooner than 30 days after the site becomes an inactive wellhead site. Following this

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inspection, the owner or operator of an inactive wellhead site shall conduct the inspections required by Paragraph (3) of Subsection (C) of 20.2.50.116 NMAC annually.

D. Alternative equipment leak monitoring plans: As an equivalent means of compliance with Subsection C of 20.2.50.116 NMAC, an owner or operator may comply with the equipment leak requirements through an alternative monitoring plan as follows:

(1) An owner or operator may comply with an individual alternative monitoring plan, subject to the following requirements:

(a) proposed alternative monitoring plans may utilize alternative monitoring methods.

(~~ab~~) the proposed alternative monitoring plan shall be submitted to and approved by the department prior to conducting monitoring under that plan.

(~~bc~~) the department may terminate an approved alternative monitoring plan if the department finds that the owner or operator failed to comply with a provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(~~cd~~) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under Subsection C of 20.2.50.116 NMAC within 15 days.

(2) An owner or operator may comply with a pre-approved monitoring plan maintained by the department, subject to the following requirements:

(a) the owner or operator shall notify the department of the intent to conduct monitoring under a pre-approved monitoring plan, and identify which pre-approved plan will be used, at least 15 days prior to conducting monitoring under that plan.

(b) the department may terminate the use of a pre-approved monitoring plan by the owner or operator if the department finds that the owner or operator failed to comply with the provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under of Subsection C of 20.2.50.116.C NMAC within 15 days.

E. Repair requirements: For a leak detected pursuant to monitoring conducted under 20.2.50.116 NMAC:

(1) the owner or operator shall place a visible tag on the leaking component until the component has been repaired;

(2) leaks shall be repaired within 15 days of discovery, except for leaks detected using OGI, which shall be repaired within seven days of discovery;

(3) the equipment must be re-monitored no later than 15 days after discovery of the leak to demonstrate that it has been repaired; and

(4) if the leak cannot be repaired within 15 days of discovery, or within seven days for a leak detected using OGI, without a process unit shutdown, the leak may be designated "Repair delayed," and must be repaired before the end of the next process unit shutdown.

F. Recordkeeping requirements:

(1) The owner or operator shall keep a record of the following for all AVO, RM21, OGI, or alternative equipment leak monitoring inspection conducted as required under 20.2.50.116 NMAC, and shall provide the record to the department upon request:

(a) facility location;

(b) date of inspection;

(c) monitoring method (e.g. AVO, RM 21, OGI, alternative method approved by the department);

(d) name of the personnel performing the inspection;

(e) a description of any leak requiring repair or a note that no leak was found; and

(f) whether a visible flag was placed on the leak or not;

(2) The owner or operator shall keep the following record for any leak that is detected:

(a) the date the leak is detected;

(b) the date of attempt to repair;

(c) for a leak with a designation of "repair delayed" the following shall be recorded:

(i) reason for delay if a leak is not repaired within the required number of days after discovery;

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(ii) signature of the authorized representative who determined that the repair could not be implemented without a process unit shutdown;
(d) date of successful leak repair;
(e) date the leak was monitored after repair and the results of the monitoring; and
(f) a description of the component that is designated as difficult, unsafe, or inaccessible to monitor, an explanation stating why the component was so designated, and the schedule for repairing and monitoring the component.

(3) For a leak detected using OGI, the owner or operator shall keep records of the specifications, the daily instrument check, and the leak survey requirements specified at 40 CFR 60.18(i)(1)-(3).

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

G. Reporting requirements:

(1) The owner or operator shall certify the use of an alternative equipment leak monitoring plan under Subsection D of 20.2.50.116 NMAC to the department annually, if used.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.116 NMAC - N, XX/XX/2021]

20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING:

A. Applicability: Liquid unloading operations including down-hole well maintenance events at natural gas wells are subject to the requirements of 20.2.50.117 NMAC.

B. Emission standards:

(1) The owner or operator of a natural gas well shall use best management practices during the life of the well to avoid the need for liquid unloading.

(2) The owner or operator of a natural gas well shall use the following best management practices during liquid unloading to minimize emissions, consistent with well site conditions and good engineering practices:

(a) reduce wellhead pressure before blowdown;
(b) monitor manual liquid unloading in close proximity to the well or via remote telemetry; and
(c) close well head vents to the atmosphere and return the well to normal production operation as soon as practicable.

(3) The owner or operator of a natural gas well shall use one of the following methods to reduce emissions during an unloading event:

(a) installation and use of a plunger lift;
(b) installation and use of an artificial lift engine; or
(c) installation and use of a control device.
(4) The owner or operator of a natural gas well shall install an EMT on the natural gas well in accordance with 20.2.50.112 NMAC.

C. Monitoring requirements:

(1) The owner or operator shall monitor the following parameters during liquid unloading:
(a) wellhead pressure;
(b) flow rate of the vented natural gas (to the extent feasible); and
(c) duration of venting to the storage vessel or atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC vented during a liquid unloading event.

(3) A liquid unloading event shall include the scanning of the EMT and monitoring data entry in accordance with the requirements of 20.2.50.112 NMAC.

(4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall keep the following records for liquid unloading:
(a) identification number and location of the well;
(b) date the liquid unloading was performed;
(c) wellhead pressure;
(d) flow rate of the vented natural gas (to the extent feasible. If not feasible, the

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owner or operator shall use the maximum potential flow rate in the emission calculation);
 (e) duration of venting to the storage vessel or atmosphere;
 (f) a description of the management practice used to minimize release of VOC emissions before and during the liquid unloading;
 (g) the type of control device used to control VOC emissions during the liquid unloading; and
 (h) a calculation of the VOC emissions vented during the liquid unloading based on the duration, volume, and mass of VOC.
 (2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
 [20.2.50.117 NMAC - N, XX/XX/2021]

20.2.50.118 GLYCOL DEHYDRATORS:

A. Applicability: Glycol dehydrators with a PTE equal to or greater than two tpy of VOC and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.118 NMAC.

B. Emission standards:

(1) Existing glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank no later than two years after the effective date. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(2) New glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank upon startup. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(3) The owner or operator of a glycol dehydrator shall comply with the following requirements:

(a) still vent and flash tank emissions shall be routed at all times to the reboiler firebox, condenser, combustion control device, fuel cell, to a process point that either recycles or recompresses the emissions or uses the emissions as fuel, or to a VRU that reinjects the VOC emissions back into the process stream or natural gas gathering pipeline;

(b) if a VRU is used, it shall consist of a closed loop system of seals, ducts and a compressor that reinjects the natural gas into the process or the natural gas pipeline. The VRU shall be operational at least ninety-five percent of the time the facility is in operation, resulting in a minimum combined capture and control efficiency of ninety-five percent. The VRU shall be installed, operated, and maintained according to the manufacturer's specifications;

(c) still vent and flash tank emissions shall not be vented to the atmosphere; and
 (d) the owner or operator of a glycol dehydrator shall install an EMT on the glycol dehydrator in accordance with 20.2.50.112 NMAC.

(4) an owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through use of a control device shall comply with the requirements in 20.2.50.115 NMAC.

(5) The requirements of Subsection B of 20.2.50.118 NMAC cease to apply when the uncontrolled actual annual VOC emissions from a new or existing glycol dehydrator are less than two tpy VOC.

C. Monitoring requirements:

(1) The owner or operator of a glycol dehydrator shall conduct an annual extended gas analysis on the dehydrator inlet gas and calculate the uncontrolled and controlled VOC emissions in tpy.

(2) The owner or operator of a glycol dehydrator shall inspect the glycol dehydrator, including the reboiler and regenerator, and the control device or process the emissions are being routed, semi-annually to ensure it is operating as initially designed and in accordance with the manufacturer recommended operation and maintenance schedule.

(3) An owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through the use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

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D. Recordkeeping requirements:

- (1) The owner or operator of a glycol dehydrator shall maintain a record of the following:
- (a) dehydrator location and identification number;
 - (b) glycol circulation rate, monthly natural gas throughput, and the date of the most recent throughput measurement;
 - (c) data and methodology used to estimate the PTE of VOC (must be a department approved calculation methodology);
 - (d) amount of controlled and uncontrolled VOC emissions in tpy;
 - (e) type, make, model, and identification number of the control device or process the emissions are being routed;
 - (f) date and results of any equipment inspection, including maintenance or repair activities required to bring the glycol dehydrator into compliance; and
 - (g) a copy of the glycol dehydrator manufacturer operation and maintenance recommendations.
- (2) An owner or operator complying with the requirements in Paragraph (1) or (2) of Subsection B of 20.2.50.118 NMAC through use of a control device as defined in this Part shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.
- (3) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.118 NMAC - N, XX/XX/2021]

20.2.50.119 HEATERS:

A. Applicability: Natural gas-fired heaters with a rated heat input equal to or greater than 10 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.119 NMAC.

B. Emission standards:

(1) Natural gas-fired heaters shall comply with the emission limits in table 1 of 20.2.50.119 NMAC.

Table 1 - EMISSION STANDARDS FOR NO_x AND CO

Date of Construction:	NO _x (ppmvd @ 3% O ₂)	CO (ppmvd @ 3% O ₂)
Constructed or reconstructed before the effective date of 20.2.50 NMAC	30	300
Constructed or reconstructed on or after the effective date of 20.2.50 NMAC	30	130

(2) Existing natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC no later than one year after the effective date of this Part.

(3) New natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC upon startup.

(4) The owner or operator of a natural gas-fired heater shall install an EMT on the heater in accordance with 20.2.50.112 NMAC.

C. Monitoring requirements:

- (1) The owner or operator shall:
- (a) conduct emission testing for NO_x and CO within 180 days of the compliance date specified in Paragraph (2) or (3) of Subsection B of 20.2.50.119 NMAC and at least every two years thereafter.
 - (b) inspect, maintain, and repair the heater in accordance with the manufacturer specifications at least once every two years following the applicable compliance date specified in 20.2.50.119 NMAC. The inspection, maintenance, and repair shall include the following:
 - (i) inspecting the burner and cleaning or replacing components of the burner as necessary;
 - (ii) inspecting the flame pattern and adjusting the burner as necessary to

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optimize the flame pattern consistent with the manufacturer specifications and good engineering practices;

(iii) inspecting the AFR controller and ensuring it is calibrated and functioning properly;

(iv) optimizing total emissions of CO consistent with the NO_x requirement, manufacturer specifications, and good combustion engineering practices; and

(v) measuring the concentrations in the effluent stream of CO in ppmvd and O₂ in volume percent before and after adjustments are made in accordance with Subparagraph (c) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC.

(2) The owner or operator shall comply with the following periodic testing requirements:

(a) conduct three test runs of at least 20-minutes duration within ten percent of one-hundred percent peak, or the highest achievable, load;

(b) determine NO_x and CO emissions and O₂ concentrations in the exhaust with a portable analyzer used and maintained in accordance with the manufacturer specifications and following the procedures specified in the current version of ASTM D6522;

(c) if the measured NO_x or CO emissions concentrations are exceeding the emissions limits of table 1 of 20.2.50.119 NMAC, the owner or operator shall repeat the inspection and tune-up in Subparagraph (b) of Paragraph (1) of Subsection C of 20.2.50.119 NMAC within 30 days of the periodic testing; and

(d) if at any time the heater is operated in excess of the highest achievable load plus ten percent, the owner or operator shall perform the testing specified in Subparagraph (a) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC within 60 days from the anomalous operation.

(3) When conducting periodic testing of a heater, the owner or operator shall follow the procedures in Paragraph (2) of Subsection C of 20.2.50.119 NMAC. An owner or operator may deviate from those procedures by submitting a written request to use an alternative procedure to the department at least 60 days before performing the periodic testing. In the alternative procedure request, the owner or operator must demonstrate the alternative procedure's equivalence to the standard procedure. The owner or operator must receive written approval from the department prior to conducting the periodic testing using an alternative procedure.

(4) Prior to a monitoring, inspection, maintenance, or repair event, the owner or operator shall scan the EMT and the required monitoring data shall be captured in accordance with this Part.

D. Recordkeeping requirements: The owner or operator shall maintain a record of the following:

(1) location of the heater;

(2) summary of the complete test report and the results of periodic testing; and

(3) inspections, testing, maintenance, and repairs, which shall include at a minimum:

(a) the date the inspection, testing, maintenance, or repair was conducted;

(b) name of the personnel conducting the inspection, testing, maintenance, or repair;

(c) concentrations in the effluent stream of CO in ppmv and O₂ in volume percent;

and

(d) the results of the inspections and any the corrective action taken.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.119 NMAC - N, XX/XX/2021]

20.2.50.120 HYDROCARBON LIQUID TRANSFERS:

A. Applicability: Hydrocarbon liquid transfers located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.120 NMAC beginning one year from the effective date of this Part.

B. Emission standards:

(1) The owner or operator of a hydrocarbon liquid transfer operation shall use vapor balance, vapor recovery, or a control device to control VOC emissions by at least ninety-eight percent when transferring liquid from a storage vessel to a transfer vessel, or when transferring liquid from a transfer vessel to a storage vessel.

(2) An owner or operator using vapor balance during a liquid transfer operation shall:

(a) transfer the vapor displaced from the vessel being loaded back to the vessel being emptied via a pipe or hose connected before the start of the transfer operation;

(b) ensure that the transfer does not begin until the vapor collection and return system is properly connected;

(c) ensure that connector pipes, hoses, couplers, valves, and pressure relief devices

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are maintained in a leak-free condition;

(d) check the liquid and vapor line connections for proper connections before commencing the transfer operation; and

(e) operate transfer equipment at a pressure that is less than the pressure relief valve setting of the receiving transport vehicle or storage vessel.

(3) Bottom loading or submerged filling shall be used for the liquid transfer.

(4) Connector pipes and couplers shall be maintained in a leak-free condition.

(5) Connections of hoses and pipes used during liquid transfer operations shall be supported on drip trays that collect any leaks, and the materials collected shall be returned to the process or disposed of in a manner compliant with state law.

(6) Liquid leaks that occur shall be cleaned and disposed of in a manner that prevents emissions to the atmosphere, and the material collected shall be returned to the process or disposed of in a manner compliant with state law.

(7) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator shall visually inspect the transfer equipment during a transfer operation to ensure that liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. Leaking components shall be repaired to prevent dripping or leaking before the next transfer operation.

(2) The owner or operator of a liquid transfer operation controlled by a control device must follow manufacturer recommended operation and maintenance procedures for the device.

(3) Tanker trucks and tanker rail cars used in liquid transfer service shall be tested annually for vapor tightness in accordance with the following test methods and vapor tightness standards:

(a) method 27 of appendix A of 40 CFR Part 60. Conduct the test using a time period (t) for the pressure and vacuum tests of five minutes. The initial pressure (Pi) for the pressure test shall be 460 mm H₂O (18 inches H₂O), gauge. The initial vacuum (Vi) for the vacuum test shall be 150 mm H₂O (six inches H₂O) gauge. The maximum allowable pressure and vacuum changes (Δp , Δv) are shown in table 1 of 20.2.50.120 NMAC.

Table 1 - ALLOWABLE CARGO TANK TEST PRESSURE OR VACUUM CHANGE

Cargo tank or compartment capacity, liters (gallons)	Allowable vacuum change (Δv) in five minutes, mm H ₂ O (inches H ₂ O)	Allowable pressure change (Δp) in five minutes, mm H ₂ O (inches H ₂ O)
< 3,785 (< 1,000)	64 (2.5)	102 (4.0)
3,785 < 5,678 (1,000 < 1,500)	51 (2.0)	89 (3.5)
5,678 < 9,464 (1,500 < 2,500)	38 (1.5)	76 (3.0)
> 9,464 (> 2,500)	25 (1.0)	64 (2.5)

(b) pressure test the tanker truck or tanker railcar tank's internal vapor valve as follows:

(i) after completing the tests under Subparagraph (a) of Paragraph (3) of Subsection C of 20.2.50.120 NMAC, use the procedures in method 27 to re-pressurize the tank to 460 mm H₂O (18 inches H₂O) gauge. Close the tank's internal vapor valve, thereby isolating the vapor return line and manifold from the tank.

(ii) relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line. After five minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable five-minute pressure increase is 130 mm H₂O (five inches H₂O).

(4) Owners and operators complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(5) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain a record of the location of the storage vessel and if using a control device, the type, make, and model of the control device:

(2) The owner or operator shall maintain a record of the inspections and testing required in Subsection C of 20.2.50.120 NMAC and shall include the following:

(a) the time and date of the inspection and testing;

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(b) the name of the personnel conducting the inspection and testing;
(c) a description of any problem observed during the inspection and testing; and
(d) the results of the inspection and testing and a description of any repair or corrective action taken.

(3) The owner or operator shall maintain a record for each site of the annual total hydrocarbon liquid transferred and annual total VOC emissions. Each calendar year, the owner or operator shall create a company-wide record summarizing the annual total hydrocarbon liquid transferred and the annual total calculated VOC emissions.

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

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20.2.50.121 PIG LAUNCHING AND RECEIVING:

A. Applicability: Pipeline pig launching and receiving operations located within or outside of the property boundary of wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.121 NMAC.

B. Emission standards:

(1) Owners and operators of pipeline pig launching and receiving operations with a PTE equal to or greater than one tpy of VOC shall capture and reduce VOC emissions by at least ninety-eight percent, beginning on the effective date of this Part.

(2) The owner or operator conducting the pig launching and receiving operation shall:
(a) employ best management practices to minimize the liquid present in the pig receiver chamber and to prevent emissions from the pig receiver chamber to the atmosphere after receiving the pig in the receiving chamber and before opening the receiving chamber to the atmosphere;

(b) employ a method to prevent emissions, such as installing a liquid ramp or drain, routing a high-pressure chamber to a low-pressure line or vessel, using a ball valve type chamber, or using multiple pig chambers;

(c) recover and dispose of receiver liquid in a manner that prevents emissions to the atmosphere; and

(d) ensure that the material collected is returned to the process or disposed of in a manner compliant with state law.

(3) The emission standards in Paragraphs (1) and (2) of Subsection B of 20.2.50.121 NMAC cease to apply to a pipeline pig launching and receiving operation if the uncontrolled actual annual VOC emissions of the operation are less than one half ton per year of VOC.

(4) An owner or operator complying with Paragraph (2) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of pig launching and receiving operations shall monitor the type and volume of liquid cleared.

(2) The owner or operator of pig launching and receiving operations shall inspect the equipment for a leak using RM 21 or OGI immediately before the commencement and immediately after the conclusion of the pig launching or receiving operation, and according to the requirements in 20.2.50.116 NMAC.

(3) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of pig launching and receiving operations shall maintain a record of the following:

(a) the pigging operation, including the date and time of the pigging operation and the type and volume of liquid cleared;

(b) the data and methodology used to estimate the actual emissions to the atmosphere and used to estimate the PTE; and

(c) the type of control device and its location, make, and model.

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(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.121 NMAC - N, XX/XX/2021]

20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS:

A. Applicability: Natural gas-driven pneumatic controllers and pumps located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.122 NMAC.

B. Emission standards:

(1) A new natural gas-driven pneumatic controller or pump shall comply with the requirements of 20.2.50.122 NMAC upon startup.

(2) An existing natural gas-driven pneumatic pump shall comply with the requirements of 20.2.50.122 NMAC within three years of the effective date of this Part.

(3) An existing natural gas-driven pneumatic controller at a site with access to commercial line electrical power, and any existing natural-gas driven pneumatic controller at a transmission compressor station or a natural gas processing plant, shall comply with this Section within six months of the effective date of this Part.

(4) At sites that do not have access to commercial line electrical power, owners and operators shall retrofit their fleet of existing natural gas-driven pneumatic controllers according to the following schedule: shall comply with the requirements of 20.2.50.122 NMAC according to the following schedule:

TABLE 1. REQUIREMENTS FOR EXISTING NATURAL GAS-DRIVEN PNEUMATIC CONTROLLERS AT WELLHEAD SITES AND TANK BATTERIES.

<u>Total Historic Percentage of Liquids Production at Facilities with Non-Emitting Controllers</u>	<u>Conversion Required by December 31, 2023</u>	<u>Maximum Percentage Requirement by December 31, 2023</u>	<u>Additional Conversion Required by May 1, 2025</u>	<u>Maximum Percentage Requirement by May 1, 2025</u>	<u>Conversion Required by May 1, 2027</u>	<u>Maximum Percentage Requirement by May 1, 2027</u>
>75%	+10	92%	+8%	94%	+3%	96%
60–75%	+15	85%	+10%	93%	+7%	95%
40–60%	+20	75%	+18%	85%	+12%	92%
20–40%	+30	60%	+25%	78%	+15%	90%
0–20%	+35	50%	+25%	75%	+25%	90%

TABLE 2. REQUIREMENTS FOR EXISTING NATURAL GAS-DRIVEN PNEUMATIC CONTROLLERS AT GATHERING AND BOOSTING STATIONS.

<u>Total Historic Percentage of Non-Emitting Controllers</u>	<u>Additional Percentage Required by May 1, 2023</u>	<u>Maximum Percentage Required by May 1, 2023</u>	<u>Additional Percentage Required by May 1, 2025</u>	<u>Maximum Percentage Required by May 1, 2025</u>
> 75 %	+15%	97%	+5%	98%
> 60-75%	+20%	90%	+10%	98%
> 40-60 %	+25%	75%	+20%	95%
> 20-40 %	+35%	65%	+25%	90%
0-20 %	+40%	55%	+35%	90%

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Table 1—WELLHEAD SITES, TANK BATTERIES, GATHERING AND BOOSTING FACILITIES

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75 %	80%	85%	90%
> 60-75 %	80%	85%	90%
> 40-60 %	65%	70%	80%
> 20-40 %	45%	70%	80%
0-20 %	25%	65%	80%

Table 2—NATURAL GAS COMPRESSOR STATIONS AND GAS PROCESSING PLANTS

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75 %	80%	95%	98%
> 60-75 %	80%	95%	98%
> 40-60 %	65%	95%	98%
> 20-40 %	50%	95%	98%
0-20 %	35%	95%	98%

(45) Standards for natural gas-driven pneumatic controllers.

(a) new pneumatic controllers shall have an emission rate of zero.

(b) existing pneumatic controllers at sites with access to commercial line electrical power, and any existing pneumatic controller at a transmission compressor station or a natural gas processing plant, shall have an emission rate of zero.

(c) At sites without access to commercial line electrical power, existing pneumatic controllers shall meet the required percentage of non-emitting controllers within the deadlines in tables 1 and 2 of Paragraph **(34)** of Subsection B of 20.2.50.122 NMAC, and shall comply with the following:

(i) by January 1, 2023, the owner or operator shall determine the total controller count for all controllers at all of the owner or operator's affected facilities that commenced construction before the effective date of this Part. The total controller count must include all emitting pneumatic controllers and all non-emitting pneumatic controllers, except that pneumatic controllers that are permitted under Subparagraph (d) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC, necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas shall not be included in the total controller count.

(ii) determine which controllers in the total controller count are non-emitting and sum the total number of non-emitting controllers and designate those as total historic non-emitting controllers.

(iii) determine the total historic non-emitting percent of controllers by dividing the total historic non-emitting controller count by the total controller count and multiplying by 100.

(iv) based on the percent calculated in (iii) above, the owner or operator shall determine which provisions of tables 1 and 2 of Paragraph **(34)** of Subsection B of 20.2.50.122 NMAC apply and the replacement schedule the owner or operator must meet.

(v) if an owner or operator meets at least seventy-five percent total non-emitting controllers by January 1, 2025, the owner or operator has satisfied the requirements of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.

(vi) if after January 1, 2027, an owner or operator's remaining pneumatic controllers are not cost-effective to retrofit, the owner or operator shall submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.

(d) a pneumatic controller with a bleed rate greater than six standard cubic feet per hour ~~zero~~ is permitted when the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to maintain operation of an emitting pneumatic controller must prepare and document the justification for the safety or

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process purposes prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be certified by a qualified professional engineer.

(56) Standards for natural gas-driven pneumatic pumps.

(a) pneumatic pumps located at a natural gas processing plants shall have an emission rate of zero.

(b) pneumatic pumps located at a wellhead sites, tank batteries, gathering and boosting sites, or transmission compressor stations with access to commercial line electrical power shall have an emission rate of zero.

(c) owners and operators of pneumatic pumps located at wellhead sites, tank batteries, gathering and boosting sites, or transmission compressor stations without access to commercial line electrical power shall reduce VOC emissions from the pneumatic pumps by ninety-five percent if it is technically feasible to route emissions to a control device, fuel cell, or process. If there is a control device available onsite but it is unable to achieve a ninety-five percent emission reduction, and it is not technically feasible to route the pneumatic pump emissions to a fuel cell or process, the owner or operator shall route the pneumatic pump emissions to the control device.

(67) The owner or operator of a pneumatic controller or pump shall install an EMT on the controller or pump in accordance with 20.2.50.112 NMAC.

C. Monitoring requirements:

(1) Pneumatic controllers or pumps with a natural gas bleed rate equal to zero are not subject to the monitoring requirements in Subsection C of 20.2.5.122 NMAC.

(2) The owner or operator of a pneumatic controller subject to the deadlines set forth in tables 1 and 2 of Paragraph (34) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each subject controller at each facility.

(3) The owner or operator of a pneumatic controller with a bleed rate greater than zero shall, on a monthly basis, scan the controller and conduct an AVO inspection, and shall also inspect the pneumatic controller, perform necessary maintenance (such as cleaning, tuning, and repairing a leaking gasket, tubing fitting and seal; tuning to operate over a broader range of proportional band; eliminating an unnecessary valve positioner), and maintain the pneumatic controller according to manufacturer specifications to ensure that the VOC emissions are minimized.

(4) The owner or operator of a pneumatic controller with a bleed rate greater than zero shall comply with the requirements in Paragraph (3) of Subsection C or Subsection D of 20.2.50.116 NMAC. During instrumental inspections, operators shall use Method 21, OGI, or alternative instruments used under Subsection D of 20.2.50.116 NMAC to verify that intermittent controllers are not emitting when not actuating. Any intermittent controller emitting when not actuating shall be repaired consistent with Subsection E of 20.2.50.116 NMAC. Pneumatic controllers found emitting detectable emissions are not subject to enforcement by the department unless the owner or operator fails to determine whether the pneumatic controller is operating properly, perform any necessary response, or keep required records, or submit reports in accordance with the rule.

(5) The EMT shall be linked to a database that contains the following:

(a) pneumatic controller identification number;

(b) type of controller (continuous or intermittent);

(c) if continuous, design continuous bleed rate in standard cubic feet per hour;

(d) if intermittent, bleed volume per intermittent bleed in standard cubic feet; and

(e) design annual bleed in standard cubic feet per year.

(56) The owner or operator of a pneumatic pump with a bleed rate greater than zero shall, on a monthly basis, scan the pump and conduct an AVO inspection and shall also inspect the pneumatic pump and perform necessary maintenance, and maintain the pneumatic pump according to manufacturer specifications to ensure that the VOC emissions are minimized.

(67) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) Pneumatic controllers and pumps with a natural gas bleed rate equal to zero are not subject to the recordkeeping requirements in Subsection D of 20.2.5.122 NMAC.

(2) The owner or operator shall maintain a record of the total controller count for all controllers at all of the owner's or operator's affected facilities that commenced operation before the effective date of this Part. The total controller count must include all emitting and non-emitting pneumatic controllers.

(3) The owner or operator shall maintain a record of the total count of pneumatic controllers

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necessary for a safety or process purpose that cannot otherwise be met without emitting VOC.

(4) The owner or operator of a pneumatic controller subject to the requirements in tables 1 and 2 of Paragraph (34) of shall generate a schedule for meeting the compliance deadlines for each pneumatic controller. The owner or operator shall keep a record of the compliance status of each subject controller.

(5) The owner or operator shall maintain an electronic record for each pneumatic controller with a natural gas bleed rate greater than zero. The record shall include the following:

- (a) pneumatic controller identification number;
- (b) inspection dates;
- (c) name of the personnel conducting the inspection;
- (d) AVO inspection result;
- (e) AVO level discrepancy in continuous or intermittent bleed rate;
- (f) maintenance date and maintenance activity; and
- (g) a record of the justification and certification required in Subparagraph (d) of

Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

(6) The owner or operator of a natural gas-driven pneumatic controller with a bleed rate ~~greater than six standard cubic feet per hour~~ greater than zero shall maintain a record in the EMT database of the pneumatic controller documenting why a bleed rate greater than ~~six scf/hr~~ zero is necessary, as required in Subsection B of 20.2.50.122 NMAC.

(7) The owner or operator shall maintain a record in the EMT database for a natural gas-driven pneumatic pump with an emission rate greater than zero and the associated pump number at the facility. The record shall include:

- (a) for a natural gas-driven pneumatic pump in operation less than 90 days per calendar year, a record for each day of operation during the calendar year.
- (b) a record of any control device designed to achieve at least a ninety-five percent emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve.
- (c) records of the engineering assessment and certification by a qualified professional engineer that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

(8) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

(9) The owner or operator of a pneumatic controller with a bleed rate greater than zero shall comply with the requirements in Subsection F of 20.2.50.116 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.122 NMAC - N, XX/XX/2021]

20.2.50.123 STORAGE VESSELS

A. Applicability: Storage vessels with an uncontrolled PTE equal to or greater than two tpy of VOC and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.123 NMAC.

B. Emission standards:

(1) An existing storage vessel with a PTE equal to or greater than two tpy and less than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-five percent no later than three years after the effective date of this Part.

(2) An existing storage vessel with a PTE equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-eight percent no later than one year after the effective date of this Part.

(3) A new storage vessel with a PTE equal to or greater than two tpy and less than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-five percent upon startup.

(4) A new storage vessel with a PTE equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-eight percent upon startup.

(5) The emission standards in Subsection B of 20.2.50.123 NMAC cease to apply to a storage vessel if the uncontrolled actual annual VOC emissions decrease to less than two tpy.

(6) If a control device is not installed by the date specified in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC, an owner or operator may comply with Subsection B of 20.2.50.123 NMAC

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by shutting in the well supplying the storage vessel by the applicable date, and not resuming production from the well until the control device is installed and operational.

~~(7) The owner or operator of a new or existing storage vessel with a thief hatch shall install a control device that allows the thief hatch to open sufficiently to relieve overpressure in the vessel and to automatically close once the vessel overpressure is relieved. The thief hatch shall be equipped with a manual lock-open safety device to ensure positive hatch opening during times of human ingress. The lock-open safety device shall only be engaged when an owner or operator are present and during an active ingress activity.~~

(8) The owner or operator of a new or existing storage vessel shall install an EMT on the storage vessel in accordance with 20.2.50.112 NMAC.

(9) An owner or operator complying with Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.115 NMAC. Owners or operators of storage vessels with a PTE or actual emissions less than or equal to 5 TPY of VOC may comply with these requirements through use of an alternative control technology approved by the department, so long as the technology shall have a combined capture and control of VOC emissions of at least ninety-five percent.

C. Storage Vessel Measurement Requirements

(1) The owners and operators of controlled storage tanks at well production facilities, natural gas compressor stations, or natural gas processing plants constructed on or after the effective date of this Part, and at any facilities that are modified on or after the effective date of this Part such that an additional controlled storage vessel is constructed to receive an anticipated increase in throughput of hydrocarbon liquids or produced water, must use a storage vessel measurement system to determine the quantity of liquids in the storage tank(s).

(2) Owners and operators subject to the storage vessel measurement system requirements in this Subsection must keep thief hatches (or other access points to the tank) and pressure relief devices on storage tanks closed and latched during activities to determine the quality and/or quantity of liquids in the storage vessel(s).

(3) Operators may inspect, test, and calibrate the storage vessel measurement system semi-annually, or as directed by the Bureau of Land Management (see 43 CFR Section 3174.6(b)(5)(ii)(B) (November 17, 2016)) or system manufacturer. Opening the thief hatch if required to inspect, test, or calibrate the system is not a violation of Paragraph (1) of this Subsection.

(4) The owner or operator must install signage at or near the storage vessel that indicates which equipment and method(s) are used and the appropriate and necessary operating procedures for that system.

(5) The owner or operator must develop and implement an annual training program for employees and third parties conducting activities subject to this Subsection that includes, at a minimum, operating procedures for each type of system.

(6) Owner or operators must retain records for at least two (2) years and make such records available to the department upon request, including:

(a) Date of construction of the storage vessel or facility;

(b) Description of the storage tank measurement system used to comply with this Subsection;

(c) Date(s) of storage vessel measurement system inspections, testing, and calibrations pursuant to Paragraph (3) of this Subsection;

(d) Manufacturer specifications regarding storage vessel measurement system inspections, and/or calibrations, if followed pursuant to Paragraph (3) of this Subsection; and

(e) Records of the annual training program, including the date and names of persons trained.

DE. Monitoring requirements: The owner or operator of a storage vessel shall:

(1) monitor on a monthly basis the total monthly liquid throughput (in barrels) and the upstream separator pressure (in psig). When a storage vessel is unloaded less frequently than monthly, the throughput and separator pressure monitoring shall be conducted before the storage vessel is unloaded;

(2) conduct an AVO inspection on a weekly basis. If the storage vessel is unloaded less frequently than weekly, the AVO inspection shall be conducted before the storage vessel is unloaded;

(3) inspect the vessel monthly to ensure compliance with the requirements of 20.2.50.123 NMAC. The inspection shall include a check to ensure the vessel does not have a leak;

(4) scan the EMT and enter the required monitoring data in accordance with the requirements of 20.2.50.112 NMAC;

(5) comply with the monitoring requirements in 20.2.50.115 NMAC if using a control device to comply with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC; and

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- 1 (6) comply with the monitoring requirements in 20.2.50.112 NMAC.
- 2 **ED. Recordkeeping requirements:**
- 3 (1) The owner or operator shall, on a monthly basis, maintain a record in accordance with
- 4 20.2.50.112 NMAC for a storage vessel. The record shall include:
- 5 (a) the vessel location and identification number;
- 6 (b) monthly liquid throughput and the most recent date of measurement;
- 7 (c) the average monthly upstream separator pressure;
- 8 (d) the data and methodology used to calculate the PTE of VOC (the calculation
- 9 methodology shall be department approved);
- 10 (e) the controlled and uncontrolled VOC emissions (tpy); and
- 11 (f) the type, make, model, and identification number of any control device.
- 12 (2) A record of liquid throughput in shall be verified by a dated delivery receipt from the
- 13 purchaser of the hydrocarbon liquid, the metered volume of hydrocarbon liquid sent downstream, or other proof of
- 14 transfer.
- 15 (3) A record of the inspection required in Subsection C of 20.2.50.123 NMAC shall include:
- 16 (a) the time and date of the inspection;
- 17 (b) the personnel conducting the inspection;
- 18 (c) a notation that the required leak check was completed;
- 19 (d) a description of any problem observed during the inspection; and
- 20 (e) a description and date of any corrective action taken.
- 21 (4) An owner or operator complying with the requirements in Paragraphs (1) through (4) of
- 22 Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the recordkeeping
- 23 requirements in 20.2.50.115 NMAC.
- 24 (5) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112
- 25 NMAC.
- 26 **E. Reporting requirements:**
- 27 (1) An owner or operator complying with the requirements in Paragraphs (1) through (4) of
- 28 Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the reporting requirements in
- 29 20.2.50.15 NMAC.
- 30 (2) The owner or operator shall comply with the reporting requirements in 20.2.50.112
- 31 NMAC.
- 32 [20.2.50.123 NMAC - N, XX/XX/2021]
- 33
- 34 **20.2.50.124 WELL WORKOVERS**
- 35 **A. Applicability:** Workovers performed at oil and natural gas wells are subject to the requirements
- 36 of 20.2.50.124 NMAC as of the effective date of this Part.
- 37 **B. Emission standards:** The owner or operator of an oil or natural gas well shall use the following
- 38 best management practices during a workover to minimize emissions, consistent with the well site condition and
- 39 good engineering practices:
- 40 (1) reduce wellhead pressure before blowdown to minimize the volume of natural gas
- 41 vented;
- 42 (2) monitor manual venting at the well until the venting is complete; and
- 43 (3) route natural gas to the sales line, if possible.
- 44 **C. Monitoring requirements:**
- 45 (1) The owner or operator shall monitor the following parameters during a workover:
- 46 (a) wellhead pressure;
- 47 (b) flow rate of the vented natural gas (to the extent feasible); and
- 48 (c) duration of venting to the atmosphere.
- 49 (2) The owner or operator shall calculate the volume and mass of VOC vented during a
- 50 workover.
- 51 (3) The owner or operator shall comply with the monitoring requirements in 20.2.50.112
- 52 NMAC.
- 53 **D. Recordkeeping requirements:**
- 54 (1) The owner or operator shall keep the following record for a workover:
- 55 (a) identification number and location of the well;
- 56 (b) date the workover was performed;

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(c) wellhead pressure;
(d) flow rate of the vented natural gas to the extent feasible, and if measurement of the flow rate is not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation;

(e) duration of venting to the atmosphere;
(f) description of the management practices used to minimize release of VOC before and during the workover; and
(g) calculation of the VOC emissions vented during the workover based on the duration, volume, and mass of VOC.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements

(1) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

(2) If it is not feasible to prevent VOC emissions from being emitted to the atmosphere from a workover event, the owner or operator shall notify by certified mail all residents located within one-quarter mile of the well of the planned workover at least three calendar days before the workover event.
[20.2.50.124 NMAC - N, XX/XX/2021]

20.2.50.125 SMALL BUSINESS FACILITIES

A. Applicability: Small business facilities as defined in this Part are subject to the requirements of 20.2.50.125 NMAC.

B. General requirements:

(1) The owner or operator shall ensure that all equipment is operated and maintained consistent with manufacturer specifications, and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available to the department upon request.

(2) The owner or operator shall calculate the VOC and NO_x emissions from the facility on an annual basis. The calculation shall be based on the actual production or processing rates of the facility.

(3) The owner or operator shall maintain a database of company-wide VOC and NO_x emission calculations for all subject facilities and associated equipment and shall update the database annually.

(4) The owner or operator shall comply with Paragraph (10) of Subsection A of 20.2.50.112 NMAC if requested by the department.

C. Monitoring requirements: The owner or operator shall comply with the requirements in Subsections C or D of 20.2.50.116 NMAC.

D. Repair requirements: The owner or operator shall comply with the requirements of Subsection E of 20.2.50.116 NMAC.

E. Recordkeeping requirements: The owner or operator shall maintain the following electronic records for each facility:

(1) annual certification that the small business facility meets the definition in this Part;
(2) calculated VOC and NO_x emissions from each facility and the company-wide VOC and NO_x emissions for all subject facilities;
(3) records as required under Subsection F of 20.2.50.116 NMAC.

F. Reporting requirements: The owner or operator shall submit to the department an initial small business certification within sixty days of the effective date of this Part, and by March 1 each calendar year thereafter. The certification shall be made on a form provided by the department. The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

G. Failure to comply with 20.2.50.125 NMAC: Notwithstanding the provisions of Section 20.2.50.125 NMAC, a source that meets the definition of a small business facility can be required to comply with the other Sections of 20.2.50 NMAC if the Secretary finds based on credible evidence that the source (1) presents an imminent and substantial endangerment to the public health or welfare or to the environment; (2) is not being operated or maintained in a manner that minimizes emissions of air contaminants; or (3) has violated any other requirement of 20.2.50.125 NMAC.
[20.2.50.125 NMAC - N, XX/XX/2021]

20.2.50.126 PRODUCED WATER MANAGEMENT UNITS

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A. Applicability: Produced water management units as defined in this Part are subject to 20.2.50.126 NMAC and shall comply with these requirements no later than 180 days after the effective date of this Part.

B. Emission standards:

(1) The owner or operator shall use best management and good engineering practices to minimize emissions of VOC from produced water management units.

(2) The owner or operator shall control VOC emissions from each produced water management unit to less than two tons per year.

C. Monitoring requirements: The owner or operator shall:

(1) calculate the monthly rolling 12-month total of VOC emissions in tons from each unit;

(2) monthly, monitor the best management and engineering practices implemented to reduce emissions at each unit to ensure their effectiveness; and

(3) comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain the following electronic records for each produced water management unit:

(a) name or identification of the unit and UTM coordinates of the unit and county;

(b) a description of the best management and engineering practices used to minimize release of VOC at the unit; and

(c) a record of the monthly rolling 12-month total VOC emissions from each unit.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.126 NMAC - N, XX/XX/2021]

20.2.50.127 REQUIREMENTS FOR FLOWBACK VESSELS AND PREPRODUCTION OPERATIONS

(A) Applicability: Wells undergoing recompletions and new wells being completed at an existing wellhead site are subject to the requirements of 20.2.50.127 NMAC one year after the effective date of this Part. New wells constructed at a new wellhead site that commence completion or recompletion after the effective date of this Part are subject to the requirements of 20.2.50.127 NMAC.

(B) Emissions standards:

(1) The owner or operator of a well must collect and control emissions from each flowback vessel on and after the date flowback is routed to the flowback vessel by routing emissions to an operating control device that achieves a hydrocarbon control efficiency of at least 95 percent. If a TO or ECD is used, it must have a design destruction efficiency of at least 98 percent for hydrocarbons.

(a) the owner or operator shall ensure that a control device used to comply with emission standards in the Part operates as a closed vent system that captures and routes VOC emissions to the control device, and that unburnt gas is not directly vented to the atmosphere.

(b) flowback vessels must be inspected, tested, and refurbished where necessary to ensure the flowback vessel is in compliance with 20.2.50.127.B(1)(a) NMAC prior to receiving flowback.

(c) the owner or operator shall use a vessel measurement system to determine the quantity of liquids in the flowback vessel(s).

(i) Thief hatches or other access points to the flowback vessel must remain closed and latched during activities to determine the quantity of liquids in the flowback vessel(s).

(ii) Opening the thief hatch or other access point if required to inspect, test, or calibrate the vessel measurement system or to add biocides or chemicals is not a violation of 20.2.50.115.H(1)(a)(i) NMAC.

(C) Monitoring:

(1) Owners and or operators of a well with flowback that begins on or after the effective date of 20.2.50 NMAC, must conduct daily visual inspections of the flowback vessel and any associated equipment, including

(a) visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly seated.

(b) visual inspection or monitoring of the control device to ensure that it is

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operating.

(c) visual inspection of the control device to ensure that the valves for the piping from the flowback vessel to the control device are open.

(D) Recordkeeping:

(1) The owner or operator of each flowback vessel subject to Paragraph (1) of Subsection B of Section 20.2.50.127 NMAC must maintain records for a period of five (5) years and make them available to the department upon request, including

(a) the API number of the well and the associated facility location, including latitude and longitude coordinates.

(b) the date and time of the onset of flowback.

(c) the date and time the flowback vessels were permanently disconnected, if applicable.

(d) the date and duration of any period where the control device is not operating.

(e) records of the inspections required in Subsection C of Section 20.2.50.127 NMAC, including the time and date of each inspection, a description of any problems observed, a description and date of any corrective action(s) taken, and the name of the employee or third party performing corrective action(s).

**20.2.50.1287 PROHIBITED ACTIVITY AND CREDIBLE INFORMATION
PRESUMPTION EVIDENCE**

A. Failure to comply with the emissions standards, monitoring, recordkeeping, reporting or other requirements of this Part within the timeframes specified shall constitute a violation of this Part subject to enforcement action under Section 74-2-12 NMSA 1978.

B. If credible evidence or information obtained by the department or provided to the department by a third party indicates that a source is not in compliance with the provisions of this Part, that information may be used by the department for the purpose of establishing whether a person has violated or is in violation of this Part.

~~**C.** If credible information provided to the department by a member of the public indicates that a source is not in compliance with the provisions of this Part, the source shall be presumed to be in violation of this Part unless and until the owner or operator provides credible evidence or information demonstrating otherwise.~~
[20.2.50.127 NMAC - N, XX/XX/2021]

HISTORY OF 20.2.50 NMAC: [RESERVED]

EDF'S EXHIBIT WW

REBUTTAL TESTIMONY OF TOM ALEXANDER

I. Documents Reviewed

In preparing my rebuttal, I reviewed the following documents:

- Direct Testimony of Ryan Davis, IPANM Ex. 2;
- IPANM's redline of the rule submitted on direct, IPANM Ex. 1;
- Testimony of John Smitherman, NMOGA App'x A1;
- NMOGA redline of the rule, submitted on direct, App'x B.
- EDF/Oxy joint proposal, EDF Ex. VV.

II. NMED HAS PROPOSED A TECHNICALLY FEASIBLE AND ECONOMICALLY REASONABLE LIQUIDS UNLOADING PROVISIONS, 20.2.50.117 NMAC

NMED has proposed a leading provision to reduce emissions during liquids unloading.

Per NMED's proposal, operators must use best management practices to avoid the need for manual unloading and to minimize emissions associated with well unloading activities. In addition, the draft requires operators to use one of three specific methods to reduce emissions during unloading events: (1) install and use a plunger lift; (2) install and use an artificial lift engine; or (3) install and use a control device. In my opinion, with the exception of the reference to an artificial lift engine, these are all effective, cost effective and technologically practicable methods to reduce emissions during liquids unloading. The provision should refer to an artificial lift pump, rather than an engine. Furthermore, these are not only standard industry practice (best management practices or "BMPs") but have been in the production engineering toolkit for decades.

During my tenure with Southwestern Energy, I supervised numerous liquids unloading events. I have considerable experience with various methods to reduce emissions during an

unloading event, including plunger lift and artificial use design, installation and operation. My experience underscores the reasonableness of the NMED proposal.

There was not a single plunger lift in operation in the Arkoma Basin in Arkansas in 1995. The general idea amongst operators and pumpers in the region at the time was that plunger lifts did not work in Arkansas. The typical method to produce was to routinely soap and blow wells to unload fluid which is very wasteful and labor intensive. I was able to secure capital in our operating budget and set about finding obvious candidates for plunger lift by running bottomhole flowing pressures and broaching the tubing to ensure the well was sound mechanically. I personally designed, supervised installation, and worked daily with the pumpers teaching them, one by one, how to operate a plunger lift. Initially there was a lot of resistance. However, the pumpers quickly saw that use of the plunger lift increased gas production and decreased the amount of time required for operation of their wells. I began receiving numerous calls per week from pumpers wanting to evaluate many of their wells for plunger lift. Within a couple years we had commingled over 100 wells and installed plunger lift successfully on literally dozens after dozens of wells, replacing the old method of soap and blow.

NMED has rightly pointed to the use of various artificial lift methods as a way to reduce emissions associated with liquids unloading activities. During the life of any well there is a producing protocol that generally begins with initial completion of a well capable of flowing to the surface unassisted. As the reservoir pressure decreases and/or line pressures increase, some form of artificial lift will become necessary to produce the well. This is all normal procedure. The form of artificial lift is basically a function of the well's GLR, production volumes, and reservoir pressure. The various forms of artificial lift are rod pumps, hydraulic pumps, gas lift, siphon strings, plunger lift or various derivatives.

III. THE EIB SHOULD REJECT IPANM'S PROPOSED REVISIONS AS THEY ARE UNNECESSARY AND, IF ADOPTED, WOULD WEAKEN THE EMISSIONS REDUCTIONS ASSOCIATED WITH THIS PROVISION

In my opinion IPANM's revisions significantly weaken the proposed rule and will result in less emissions reductions.

First, IPANM proposes to limit the applicability of the liquids unloading provision to manual unloading events only. IPANM redline, Ex. 1. I disagree with this proposal as it will significantly narrow the applicability of the rule by totally ignoring emissions from artificial lift technologies used during non-manual unloading activities. While resulting in far fewer emissions than manual unloading, the use of artificial lift technologies to unload a well nevertheless results in some emissions.

Second, I also strongly disagree with IPANM's proposal to strike the use of the three specific methods to reduce emissions during unloading events in proposed 20.2.50.117.B.(3). First, as noted above, the methods to reduce emissions during unloading listed by NMED in 20.2.50.117.B.(3) are all feasible and economic. Second, IPANM's has put forward no clear arguments to refute the feasibility of using the methods listed in 20.2.50.117.B.(3). While I agree with Mr. Davis that a plunger lift is not suitable for every well, the NMED proposal does not require the use of a plunger lift on every well. The success of plunger lift is ultimately actually dependent upon the gas to liquids (GLR) and reservoir pressure. The draft rule gives operators flexibility to choose from a list of methods. All the other issues mentioned by Mr. Davis in his testimony (tubing size, wellhead configuration, wellbore, production equipment, etc.) are mechanical in nature and can be modified to accommodate an optimum plunger lift application, barring downhole mechanical deformities. I have on numerous occasions converted something as complicated as a triple completion into a very successful plunger lift application

with a single tubing string. While Mr. Davis's testimony presents a basic discussion of unloading, IPANM's has not presented any conclusive evidence whatsoever to support their contention that NMED should strike proposed 20.2.50.117.B.(3).¹

IV. NMOGA's proposed revisions to proposed 20.2.50.117 NMAC

In my opinion NMOGA's revisions significantly weaken the proposed rule and will result in less emissions reductions.

First, NMOGA also proposes NMED revise its rule to apply only to manual unloading. As noted above, I disagree with this. I strongly disagree with testimony that "only manual liquid unloading involving venting to the atmosphere would result in emissions" since artificial lift methods, such as plunger lifts, can result in some minimal emissions.²

Second, NMOGA has proposed revisions to 20.2.50.117.B.(3).³ I do not agree with these revisions but suggest some minor clarifications to this provision as follows. These revisions reflect the fact that all the listed methods in proposed 20.2.50.117.B.(3) are forms of artificial lift technology. In addition, I suggest NMED replace the term "engine" with "pump" as it is the pump's action that unloads a well, not the engine. The engine merely operates the pump via hydraulics or a rod string. Lastly, I suggest adding a fourth type of artificial lift, use of a rod pump, to the list of methods operators may use to reduce emissions during unloading events. Specifically, the final rule would be more technically correct if it were revised as follows:

The owner or operator of a natural gas well shall use **one of the following artificial lift technologies** ~~or one of the following methods~~ **or an equally effective method approved by the Department** to reduce emissions during an unloading event:

- (a) installation and use of a plunger lift;
- (b) installation and use of an artificial lift ~~engine~~ **pump**; ~~or~~
- (c) installation and use of a control device; or
- (d) installation and use of a rod pump.**

¹ Ryan Davis, IPANM, Ex. 2.

² John Smitherman, NMOGA NOI, Appendix A1, p.25, lines 20-21.

³ NMOGA, Appendix B, Redlines, p. 36.

These proposed revisions in no way weaken nor change the substantive control requirements of the rule. In my opinion they make the rule more technically accurate and clear.

I also suggest that the term “close proximity” be defined or clarified in implementation guidance regarding the process of monitoring the manual unloading process. Manual unloading should be discouraged and used by operators as a last result given the potential for CH₄ and VOC emissions, and waste, associated with this practice. As drafted, the rule places no bounds on how far an operator may wander from a well site during a manual unloading event, or what methods an operator must use to remotely monitor a well during a manual unloading event. This lack of clarity and specificity in the rule may result in excess venting during manual unloading events that could be prevented with greater rule specificity.

Third, Mr. Smitherman states blowing a well to the atmosphere to unload is the “best alternative to restoring production.”⁴ While it is *a* way to restore production, I disagree it’s the best way. In fact, repeated manual unloading to the atmosphere is wasteful of the resource, an inefficient use of manpower and of course emits harmful CH₄ and VOCs to the environment. In my considerable experience with low pressure gas wells, the best method of artificial lift is a plunger lift, assuming the well’s GLR is appropriate. Additionally, keeping a well unloaded will increase near-term production, thus enhancing the well’s economics. One can also adjust the surface facilities to accommodate plunger lift with little or no venting as the plunger travels to the surface with a load of fluid.

Fourth, NMOGA proposes two years to comply with the liquid unloading provisions in 20.2.50.117.B.(2).⁵ It is unclear why this is proposed since they want the rule to only address

⁴ John Smitherman, NMOGA NOI, Appendix A1, p. 25, lines 11-13.

⁵ NMOGA, Appendix B, Redlines, p. 36.

manual unloading that results in venting CH₄ to the atmosphere. I think there should be a time stamp on application of BMP artificial lift to eliminate to the maximum extent possible the practice of manual unloading. As proposed, operators would need to comply with the liquids unloading provisions when the rule becomes effective. I support this implementation date. Moreover, since artificial lift is almost always preferable to manual unloading, NMED should require a solid mechanical justification presented by the operator in support of manual unloading versus application of BMP artificial lift.

Fifth, NMOGA wants to strike 20.2.50.117 C. (1)(b).⁶ I disagree. There is no justification for not monitoring or estimating the flowrate during unloading.

Last, I agree with NMOGA's witness, John Smitherman, that NMED should allow operators to use "smart" systems to reduce emissions during an unloading event. This is a wise application of new/emerging technologies to optimize well production and economics. However, it is important that surface facilities and artificial lift systems be altered and installed to reduce emissions as much as possible. Smart technology cannot be a license to unnecessarily emit natural gas if other technologies can be used to avoid emissions.

V. EDF AND OCCIDENTAL PETROLEUM COMPANY HAVE AGREED TO CERTAIN PROPOSALS THAT IMPROVE THE WORKABILITY OF THE RULE

I have reviewed Occidental Petroleum Company's direct testimony and revisions to the NMED proposal and the Joint EDF and Oxy Proposal submitted as EDF Ex. VV. I agree with the following joint proposals for the reasons noted below:

(1) 20.2.50.123.B.(7) (remove requirement to install a control device on thief hatches). Oxy proposes NMED strike the proposed provision requiring operators install control

⁶ NMOGA, Appendix B, Redlines, p. 37.

device on thief hatches. I am not familiar with a device that can be used as a control device on a thief hatch. I support removal of this requirement as technically infeasible.

(2) Proposed 20.2.50.127(A),(B)(1)(a)-(c) (requirements for flowback vessels and preproduction operations). EDF has made slight revisions to this proposal based on conversations with Oxy. First, we moved this provision to its own stand-alone section in the rule rather than including as a sub-paragraph to "control devices." Second, we jointly propose with Oxy a one-year implementation timeframe for operators of existing wells undergoing recompletions and operators of new wells being completed at an existing wellhead site. Third, we have replaced the term "vapor tight" with "operates as a closed vent system" as the latter is a clear term understood and commonly used by the industry.

EDF'S EXHIBIT XX

REBUTTAL TESTIMONY OF DAVID LYON

I. DOCUMENTS REVIEWED

In preparing my rebuttal, I reviewed the following documents:

- NMOGA redline to NMED proposed rule, NMOGA Statement of Intent to Present Technical Testimony, Appendix B.
- Ryan Davis testimony, IPANMs Ex. 2.
- ERG LDAR Reductions and Costs VOC Spreadsheet, NMED Ex. 69.
- Deighton, Jacob A. et al., *Measurements show that marginal wells are a disproportionate source of methane relative to production*, 70(10) J. AIR & WASTE MGMT. ASSOC. 1030 (Aug. 2020), EDF Ex. YY
- Omara, M. et al., *Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate*, 52 ENVTL. SCI. TECHNOL. 12915 (Sept. 2018). EDF Ex. ZZ.
- Allen et al., *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings*, 49:1 ENVTL. SCI. TECHNOL. 641–648 (2015) (“Allen et al. (2015)”), EDF Ex. AAA.

II. EDF, CLEAN AIR ADVOCATES, CENTER FOR CIVIC POLICY, NAVA EDUCATION PROJECT AND OCCIDENTAL PETROLEUM COMPANY JOINT PROPOSAL

EDF, in conjunction with Clean Air Advocates, Center for Civic Policy, and NAVA Education Project (environmental and tribal coalition) have reached agreement with Occidental Petroleum Company (Oxy) regarding several improvements and revisions to the NMED draft rule. Notably, Oxy is agreeing to all of EDF and our partners' proposed revisions, with some

modifications. We are agreeing to a number of Oxy's proposed revisions as they clarify and improve the feasibility of the rule. My testimony will discuss several of the areas of agreement.

First, EDF and Oxy have agreed to add a new provision to EDF's LDAR Proximity Proposal, 20.2.50.116.C.(3)(c) NMAC. EDF's LDAR Proximity Proposal requires operators with wellhead sites located within 1,000 ft. of occupied places such as schools, playgrounds and homes, to inspect such facilities more frequently than would otherwise be required by the NMED proposal. This proposal increases reductions in harmful air pollutants and provides critical protections for the health of those living, working, or recreating near oil and gas facilities.

Oxy has agreed to this proposal. To help ensure the smooth implementation of this rule and provide for a clear compliance pathway, we have agreed to adding a provision that specifies a date certain when operators must conduct a compliance evaluation to determine if one of their wellhead sites is subject to the proposed leak enhanced inspection requirements. Specifically, operators must evaluate applicability of the proximity-based LDAR requirements to the operator's wellhead sites annually on March 15 for existing wellhead sites and within thirty (30) days of constructing a new facility. In addition, we have suggested a provision wherein a homeowner may contact NMED to request that an operator conduct an evaluation of a particular wellhead site to determine if it is within 1,000 ft. of the home-owner's house. Per this provision NMED must request that the operator include the homeowner's house in the annual applicability evaluation conducted by an operator.

We also jointly propose NMED agree to issue guidance materials to operators specifying how to measure the 1,000 ft. We propose operators measure this distance from the permitted lat/long of each well head at the well site to the following locations for "occupied places:"

- (1) Property line for schools and outdoor venue/recreation areas;

(2) Location of building or structure used as place of residence'

(3) Location of commercial building.

EDF has agreed to the following revisions proposed by Oxy:

- 20.2.50.111.B (allowing an in-house engineer with expertise regarding the calculation of potential to emit to certify this calculation). We agree with Oxy that in-house engineers can competently make this calculation. Moreover, NMED has the ability to require an owner or operator to retain a third party to verify any information or data reported to NMED.
- 20.2.50.112.B(2)(a) (providing an exception for operators who use an alternative monitoring plan from the requirement to scan an Electronic Monitoring Tag before and after a monitoring event). We agree with Oxy that incentivizing the use of emerging LDAR technologies such as aerial screening methods is important. Many aerial methods are quite effective at detecting emissions from equipment. Such methods can be used in lieu of ground-based LDAR.
- 20.2.50.112 (allowing operators to use their own databases to generate a CDR). Oxy has proposed NMED allow operators to use their own database to generate a Compliance Database Report (CDR) provided the CDR is "adequate to provide the department with compliance assurance." Oxy redline, 20.2.50.112.(3). We recognize that some operators have invested significant resources in developing their own databases and agree with Oxy that providing flexibility to operators to use their databases helps improve the workability of the rule.
- 20.2.50.116.C.(4)(exceptions to LDAR requirements for non or low-emitting sources). We agree with Oxy that it is unnecessary to inspect facilities that do not

emit pollutants, or to frequently inspect facilities that are unlikely to emit significant pollutants. Thus, we have proposed several revisions to the instrument based LDAR provisions, along with specific definitions to make clear precisely which types of facilities do not emit VOCs or methane. Per these revisions, we propose that inactive wellheads be inspected no sooner than 30 days after the site becomes an inactive wellhead site. Following this inspection, the owner or operator of an inactive wellhead site shall conduct the inspections required by Paragraph (3) of Subsection (C) of 20.2.50.116 NMAC annually. We propose no instrument based LDAR for satellite facilities, injection wellhead sites, and temporarily abandoned wellhead sites given that such facilities do not emit VOCs or CH₄.

- 20.2.50.116.D (specifying that operators may use an approved alternative monitoring method to conduct LDAR). We agree with Oxy that the alternative equipment leak monitoring plan provision should allow operators to apply to NMED to use "alternative monitoring methods." Examples of alternative monitoring methods include aerial screening methods such as fixed-wing or helicopter surveys that can effectively detect leaking and abnormally operating conditions.
- 20.2.50.122. (revisions to the pneumatic controller retrofit requirements). Oxy and EDF have agreed to a new schedule that provides for retrofits of existing gas-powered pneumatic controllers at wellhead sites. In my opinion the retrofit requirements will result in additional emissions reductions than would otherwise be achieved by the NMED proposal. In addition, we have jointly agreed that operators should use historic liquids production to determine which of the retrofit requirements apply. I agree with Oxy that liquids production is a metric of intermittent vent actuation and

thus it is the best metric to determine applicability of the retrofit requirements. We have also agreed to add a new provision, 20.2.50.122.C.(4), regarding enforcement of our proposal to inspect gas-powered pneumatic controllers during LDAR.

Specifically, per our proposal, pneumatic controllers found emitting detectable emissions are not subject to enforcement by the Department unless the owner or operator fails to determine whether the pneumatic controller is operating properly, perform any necessary response, keep required records, or submit reports in accordance with the rule. This provision recognizes the challenges some operators may face when inspecting continuous bleed controllers using OGI or similar methods that do not quantify a bleed rate.

- 20.2.50.123.B(9)(allowing an operator to obtain NMED approval to use an alternative control for storage tanks). We agree with Oxy that NMED should allow operators to apply for approval to use an alternative control technology to control emissions from low-potential to emit storage tanks, provided the alternative control technology has "a combined capture and control of VOC emissions of at least ninety-five percent." This revision will help ensure operators do not need to bring onsite supplemental fuel to power combustors or control devices at low-emitting storage tanks.

III. NMED DID NOT OVERESTIMATE POLLUTION REDUCTIONS THAT CAN BE ACHIEVED THROUGH LDAR

I reviewed NMOGA's analysis, contained in their redline of the NMED proposal and ERG's estimate of emission reductions to result from implementation of NMED's proposed rules. I disagree with the assertion that NMED has overestimated pollution reductions that can be achieved by requiring operators to routinely inspect their facilities for leaks and abnormal operating conditions. ERG estimates that the 23,969 well sites in New Mexico subject to the

proposed LDAR requirements emit 7,131 tons of VOCs that can be reduced by frequent inspections. NMED Ex. 69. This is a gross underestimate of the pollution emitted from New Mexico well sites that can be reduced by frequent leak inspection and repair requirements based on recent direct measurement studies. Specifically, as noted in my direct testimony, in 2018 Robertson et al conducted vehicle-based methods to survey 71 oil and gas well sites in the Permian Basin. Per this study, Robertson estimated annual average well pad emissions in the New Mexico Permian Basin are 37 tons per year of methane. EDF Ex. F. This well pad methane emission rate is equivalent to approximately 11 tons per year of volatile organic compounds (VOCs).¹ Other studies, such as the Permian Basin studies discussed in my direct testimony (specifically EDF Exhibits D, E, G, H, and I) suggest Robertson's estimate is low because it excludes emissions from elevated sources like flares that pass over vehicle-based measurement platforms.

NMOGA asserts that NM facilities have "less potential equipment leak emissions" than EPA's model plant that ERG used to model the reductions associated with NMED's LDAR proposal. NMOGA NOI, Appendix B. pp. 30. NMOGA bases this assertion on reports operators submit to EPA pursuant to EPA's Greenhouse Gas Reporting Program. Per these reports, according to NMOGA, New Mexico facilities "have, on average, less pieces of major equipment, less components, and less potential equipment leak emissions than the 2016 CTG Model Plants." *Id.* at p. 30.

As noted above, direct measurements taken this year and the past several years in the Permian Basin demonstrate that measured emissions are significantly higher than operator

¹ EDF converted this number to volatile organic compounds, using a 3.44 CH₄:VOC for Oil wells and 2.88 CH₄:VOC for Gas wells. Using the number of each type of well in the Permian EDF created a weighted average of 3.327 CH₄:VOC to convert the Robertson et al methane emission estimate to VOC.

reports. EPA's model plant relied on an estimate of emissions, not on direct measurement of emissions in the Permian Basin. Thus, while I agree with NMOGA that EPA's estimate of emissions in the 2016 Model Plant is inaccurate, I come to the opposite conclusion of NMOGA with respect to the status of current emissions in NM. Robertson *et al*'s empirical estimates of NM Permian Basin well sites methane emissions are ~10X higher than operator reports to EPA pursuant to EPA's Greenhouse Gas Reporting Program would suggest.

IV. I DISAGREE WITH NMOGA THAT COMPONENTS TRANSFERRING FLUID THAT IS LESS THAN 10% VOC BY WEIGHT OR HANDLE COAL BED METHANE SHOULD BE EXEMPT FROM THE NMED PROPOSED LDAR REQUIREMENTS. (NMOGA REDLINE AT P. 39)

Components transferring fluid that is less than 10% VOC by weight or handle coal bed methane can leak methane. Methane is a powerful short-term climate forcer with over 80 times the global warming potential of carbon dioxide on a mass basis over the first 20 years after it is emitted. The Governor has stated that reducing methane emissions is a critical priority for New Mexico. NMED Ex. 7. It is therefore important that NMED reduce methane emissions as well as ozone precursors.

Our analysis, as explained by Hillary Hull's rebuttal testimony, demonstrates that the leak detection and repair requirements proposed by NMED are highly cost effective and in line with LDAR requirements prepared by other oil and gas producing states such as Colorado. Our analysis did not exempt components that transfer fluid that is less than 10% VOC by weight or handle coal bed methane. Nor do Colorado's rules. I do not agree that with NMOGA's proposed exemptions as they will reduce critically needed reductions in methane.

V. I DISAGREE WITH NMOGA THAT WELL SITES THAT HAVE A PTE OF LESS THAN 10 TPY OF VOCS SHOULD BE SUBJECT TO LESS FREQUENT INSPECTIONS THAN NMED PROPOSED.

Studies demonstrate low-producing wells are significant emitters

Low-producing wells are the most abundant type of oil and gas well in the United States, and a surprising number of them are venting all of or more than their reported produced gas into the atmosphere. EDF Ex. YY. This makes low-producing wells a disproportionate source of VOC and methane emissions compared to their energy production and underscores the need for robust control requirements.

A 2020 study involving direct measurements of methane and VOC emissions from marginal oil and gas wells (wells producing less than 1 BOE/d) in the Appalachian Basin of southeastern Ohio found that marginal wells are a disproportionate source of methane and VOCs relative to oil and gas production. The study estimated that oil and gas wells in this lowest production category emit approximately 11% of total annual methane production from upstream oil and gas sources in the EPA greenhouse gas inventory, although they produce about 0.2% of oil and 0.4% of all gas produced in the US per year. EDF Ex. YY.

Another recent study involving site-level measurements of over 70 Permian Basin well pads found no relationship between emissions and production. Per the study, wells with production below 10 barrels of oil equivalent per day had similar emissions as non-marginal wells, based on a comparison of absolute methane emissions and gas production by site. EDF Ex F.

A 2018 study of sites in eight basins across the US is in accord. Researchers obtained site-level methane emissions data from over 1000 natural gas production sites, including 92 new site-level methane measurements in the Uinta, northeastern Marcellus, and Denver-Julesburg Basins, to investigate methane emissions characteristics and develop a new national methane emission estimate for the natural gas production segment. The study looked at natural gas production sites and categorized them as low (sites producing <100 Mcfd), intermediate (100 to

1000 Mcfd), and high (>1000 Mcfd). Low natural gas production sites accounted for 85% of the total number of sites in the study and nearly two-thirds (63%) of the total methane emissions.

EDF Ex. ZZ

Several past studies have reported measurement-based results for methane leakage from low-production oil and gas (“O&G”) wells. These studies varied in geography and scope; while some focused on low-production wells, others measured low production wells as part of a larger measurement campaign that also included non-low production wells. We have identified seven of these studies based on the criteria that they reported both the measured site-level methane emissions and the O&G production data.

The studies reveal wide variability in methane leakage rate at the site-level, ranging from 0 to 22 kg/h/site (median = 0.32 kg/h/site = 2.8 metric tons/year; average = 1.2 kg/h/site = 10.5 metric tons/year). Similarly, as a fraction of their methane production, the data show that methane loss rates from these sites ranged from 0 to >100%. More than one-quarter (28%) of the measured sites emitted >1 kg/h/site (or > 8.8 metric tons/year) and nearly one-third (31%) emitted more than 10% of their production. The top 5% of high emitting sites accounted for approximately 50% of the total measured methane emissions, indicating that the phenomenon of “super-emitting” sites that has been observed throughout the O&G supply chain is also prevalent among these low-producing sites.

These studies identified poor maintenance as one of the primary drivers of observed methane leakage at these sites. For example, Deighton et al. (2020) observed that the “state of maintenance at these wells was poor;” some sites were in a state of disrepair (e.g., rusty well shafts, broken valves, etc), while others were found to be venting as a result of fallen trees on the wellheads. EDF Ex. YY. Similarly, Omara et al. (2016) reported “rusted or corroded well

casings, field piping, regulators, valves and meters,” and identified a few of these decrepit components as “substantial sources of leaks” at the low-production well sites. EDF Ex. ZZ. These avoidable methane emissions are not well represented in traditional emission factor calculations and contribute to the significant differences that have often been observed between inventory-based estimates and measurement studies.

The studies assessed here indicate that low-production wells are likely a disproportionately large source of O&G methane emissions nationally. For example, for the very low production category of 0-1 boe per day wells, Deighton et al. (2020) estimate that these wells account for 11% of the production-related methane emissions in the EPA’s Greenhouse Gas Inventory. Similarly, Omara et al. (2018) estimated that 63% of production-related methane emissions come from well sites that produce <100 Mcfd. Therefore, mitigating the methane emitted from these sites could reduce a significant proportion of O&G methane emissions nationally.

These studies demonstrate that controlling low producing wells is essential to curbing emissions from oil and gas facilities.

VI. GAS-POWERED PNEUMATIC CONTROLLERS CAN EMIT SIGNIFICANT POLLUTION WHEN MALFUNCTIONING AND SHOULD BE ROUTINELY INSPECTED

I reviewed Ryan Davis's testimony regarding pneumatic controllers. He notes that Merrion Oil & Gas Corporation replaced all continuous bleed liquid leveler controllers with intermittent bleed controllers as a way to reduce greenhouse gas emissions. Direct Testimony of Ryan Davis, IPANM Ex. 2, p.15, lines 4-6. He states that a properly functioning intermittent bleed device has lower emissions than a low bleed continuous controller. *Id.*, lines 21-23. He

also notes that the emission factor used by NMED for intermittent controllers is outdated and overstated. *Id.*, p. 15, line 23-p.16, lines 1-2.

I agree with Mr. Davis that a properly functioning intermittent controller emits less than 13.5 scf/hr. However, malfunctioning intermittent controllers can emit significantly more than this amount, and significantly more than a properly functioning continuous bleed controller. EDF Ex. AAA. That is why EDF has proposed that New Mexico require operators periodically inspect intermittent controllers during LDAR inspections. EDF Ex. VV. As I stated in my direct testimony, intermittent and continuous bleed controllers can malfunction, and when they do, they can vent pollution far in excess of the amount operators estimate when reporting controller emissions to regulators for inventory purposes. The direct measurement studies I discuss in my direct testimony summarizes the results of the scientific studies documenting this phenomenon.

Colorado has required operators to inspect intermittent and continuous bleed pneumatic controllers since 2017. Mr. Davis's testimony notes that Colorado uses a lower emission factor than NMED to estimate emissions from intermittent controllers. This is because Colorado's rules requiring inspections of intermittent controllers have resulted in a reduction of emissions caused by malfunctioning controllers. Thus, it is appropriate for Colorado to use a lower emission factor for intermittent controllers. New Mexico, however, has no such pneumatic controller inspection requirement in place and thus there is no program in place to address emissions from malfunctioning pneumatic controllers. That is why EDF is proposing NMED require operators inspect gas-powered pneumatic controllers as part of LDAR inspections.

EDF'S EXHIBIT YY

TECHNICAL PAPER



Measurements show that marginal wells are a disproportionate source of methane relative to production

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ABSTRACT

Oil and natural gas wells are a prominent source of the greenhouse gas methane (CH_4), but most measurements are from newer, high producing wells. There are nearly 700,000 marginal “stripper” wells in the US, which produce less than 15 barrels of oil equivalent (BOE) d^{-1} . We made direct measurements of CH_4 and volatile organic carbon (VOC) emissions from marginal oil and gas wells in the Appalachian Basin of southeastern Ohio, all producing $< 1 \text{ BOE d}^{-1}$. Methane and VOC emissions followed a skewed distribution, with many wells having zero or low emissions and a few wells responsible for the majority of emissions. The average CH_4 emission rate from marginal wells was 128 g h^{-1} (median: 18 g h^{-1} ; range: $0\text{--}907 \text{ g h}^{-1}$). Follow-up measurements at five wells indicated high emissions were not episodic. Some wells were emitting all or more of the reported gas produced at each well, or venting gas from wells with no reported gas production. Measurements were made from wellheads only, not tanks, so our estimates may be conservative. Stochastic processes such as maintenance may be the main driver of emissions. Marginal wells are a disproportionate source of CH_4 and VOCs relative to oil and gas production. We estimate that oil and gas wells in this lowest production category emit approximately 11% of total annual CH_4 from oil and gas production in the EPA greenhouse gas inventory, although they produce about 0.2% of oil and 0.4% of gas in the US per year.

Implications: Low producing marginal wells are the most abundant type of oil and gas well in the United States, and a surprising number of them are venting all or more of their reported produced gas to the atmosphere. This makes marginal wells a disproportionate greenhouse gas emissions source compared to their energy return, and a good target for environmental mitigation.

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Introduction

The oil and gas industry is responsible for nearly a third of anthropogenic emissions of the greenhouse gas methane (CH_4) in the United States (US EPA 2017), although recent estimates have nearly doubled EPA estimates of oil and gas CH_4 emissions (Alvarez et al. 2018). Most CH_4 emissions from the oil and gas industry come from producing wells, although most measurements have been from unconventional wells which produce at the highest rates (Brantley et al. 2014; Omara et al. 2016; Rella et al. 2015). However, the majority of oil and gas wells in the United States are conventional wells, which were drilled from the 1860s to present, and produce at lower rates (US Energy Information Administration 2018). Not only are oil and gas wells a source of CH_4 , they are a source of non-methane hydrocarbons and volatile organic carbon (VOCs), which can serve as ozone precursors and have a direct impact on human health (Brantley, Thoma, and Eisele 2015; Marrero et al. 2016; Tran et al. 2020). As oil and gas production in

Ohio and the larger Appalachian Basin continues to increase due to unconventional oil and gas operations (U.S. Energy Information Administration 2017), it is essential to study the impact and legacy of existing infrastructure.

A marginally producing or “stripper” well is defined by the Internal Revenue Service as a well that produces less than 15 barrels of oil equivalent or less than 90,000 cubic feet (90 MCF) of natural gas per day (Internal Revenue Service 2019; US Energy Information Administration 2018). Over 695,000 of the 872,000 active oil and gas wells in the United States are marginally producing (US Energy Information Administration 2018). In 2015, 11% of the United States’ natural gas and 10% of the United States’ oil came from marginal wells (US Energy Information Administration 2018). Federal and state tax incentives for marginal wells are designed to help keep these wells in production, particularly when prices drop below a certain threshold (Potter et al. 2017). Before the onset of hydraulic fracturing, marginal wells

were the dominant source of domestic oil in many regions of the United States.

The Appalachian Basin is the oldest commercially producing oil and gas basin in the world and was home to the beginnings of the oil and gas industry in the United States in the mid-1800s. Ohio has an estimated 220,000 conventional oil and gas wells but only around 60,000 are currently active, many of which are marginally producing (Ohio Division of Geological Survey 2004). There are also an unknown number of both plugged and unplugged abandoned oil and gas wells in Appalachia (Brandt et al. 2014; Townsend-Small et al. 2016). Over the past decade, the Appalachian region has been targeted for drilling in the underlying Utica and Marcellus shale formations using unconventional oil and gas extraction techniques (U.S. Energy Information Administration 2017). Ohio has a large number of marginal wells, mostly in the category of producing less than 1 barrel of oil equivalent per day. Of the ~12,000 oil wells in Ohio, 84% produce less than 1 barrel per day; 73% of the ~29,000 gas wells in Ohio produce less than 1 barrel equivalent per day (US Energy Information Administration 2018). Despite the large presence of these wells in the state, in 2018, marginal wells were responsible for only 1.5% of gas and 24% of oil production in Ohio (US Energy Information Administration 2018), reflecting the dominance of a small number of high producing hydraulic fracturing wells in state production numbers, particularly for natural gas. Before fracking came to the state in ~2012, marginal wells produced 75–85% of oil in Ohio from 2000 to 2011.

There are only a few studies of environmental impacts of the oil and gas industry in the Appalachian Basin of Ohio (Botner et al. 2018; Elliott et al. 2018; Paulik et al. 2016), primarily focused on impacts of unconventional oil and gas development. One study investigated the concentrations of polycyclic aromatic hydrocarbons (PAHs) in ambient air from unconventional oil and gas development in Carroll County, Ohio (Paulik et al. 2016). Some PAHs, like benzo(a)pyrene are known human carcinogens (United States Environmental Protection Agency 2008). The study in Carroll County used passive samplers to determine the risk of exposure to PAHs in relation to unconventional well operations and their results showed that concentrations of PAHs decreased with distance from unconventional oil and gas activities (Paulik et al. 2016). Other studies have explored the impacts of unconventional oil and gas activities on groundwater. One study investigated CH₄ migration into drinking water wells in eastern Ohio, a hot spot for unconventional oil and gas operations. They found no link between distance from active

wells and CH₄ concentrations in groundwater (Botner et al. 2018). However, another study in the same region found a relationship between non-methane organic constituents in drinking water and proximity to unconventional oil and gas operations (Elliott et al. 2018). A study of abandoned conventional wells in the Appalachian Basin of Ohio found that they emit CH₄ at a rate of about 14 g h⁻¹ (Townsend-Small et al. 2016), but other studies of CH₄ emissions from conventional oil and gas wells in Appalachia have focused on Pennsylvania or West Virginia (Kang et al. 2014; Omara et al. 2016; Riddick et al. 2019).

Here we report data collected from direct measurements made at the component level of CH₄ emissions from marginally producing conventional oil and gas wells in the Wayne National Forest of southeastern Ohio. Measurements were taken at 48 locations throughout the three sections of the forest. The overall goal of this study is to describe the emission profile of CH₄ and other VOCs from marginally producing conventional wells on public land in Ohio. The research questions were: 1), what is the range of emissions from marginally producing wells; 2), what proportion of their production is lost to the atmosphere; 3), are CH₄ emissions from marginal wells episodic or are they sustained over several months to a year; and 4), what is the magnitude of harmful air pollution emissions from marginal wells?

Methods

Study area

Since the late 1800s, over 200,000 wells have been drilled in Ohio (Ohio Division of Geological Survey 2004). This study was conducted in the Wayne National Forest in southeastern Ohio, USA. The Wayne National Forest has three units in the Athens, Marietta, and Ironton regions of Ohio. The Wayne National Forest has nearly 1,300 conventional oil and gas wells and an unknown number of inactive wells (“ODNR Oil & Gas Well Viewer,” 2019). Some of these wells were drilled before the land became public and some were drilled after the US government purchased the land. There are plans for unconventional drilling in the Wayne National Forest. Several auctions for mineral rights and land access have taken place, however, no drilling permits have been issued.

Site selection

Measurements were taken at 48 different wells. The wells in this study were located using the ODNR’s interactive well locator map provided by ODNR’s Division of Oil

and Gas (“ODNR Oil & Gas Well Viewer,” 2019). Wells were selected according to several attributes: public land status, proximity to a public road, and producing status.

For this study, we only measured easily accessible actively producing wells on federal land in the Wayne National Forest. Because the Wayne National Forest is a patchwork of public and private land, to avoid trespassing on private land we first located wells on federal land adjacent to public roads in the ODNR Oil and Gas Well Finder. After preliminary site selection according to these parameters, accessibility was further verified with Google Earth. In addition, we added a Garmin HuntView microSD card in our GPS for use during field sampling to ensure that we only sampled wells were that were on public land. The operational and maintenance status of the wells was variable from well to well. Some sites visited were in a state of disrepair (e.g. rusty well shafts, broken valves, fallen trees), while others were maintained with fresh paint and greased fittings. Where it was included in our field notes, the maintenance status of each well is included in Table 1. Tanks and gathering lines were common infrastructure found near wellheads, but we did not sample from tanks or gathering lines. Most wells were sampled once, but five wells were sampled between two and four times over a 13-month period to assess variability in emission rate over time. Emission rates for these wells are presented as an average of each measurement in Table 1 and Figure 1 and individual emission rates are shown in Figure 2.

Production data for the wells we sampled were taken from the ODNR production database and is shown in Table 1. Most wells produced only oil or gas, and a few produced both (Table 1), but all of the wells were listed as “producing” or “active” by ODNR, even if they had a production rate of 0 for 2018 (4 out of 48 wells in Table 1). Annual production of natural gas for 2018 (the most recent year available) for the wells visited ranges from 0 to 2584 MCF, with an average of 349 MCF. The annual production of oil ranges from 0 to 214 barrels for 2018, with an average of 30 barrels (“Oil & Gas Well Production Numbers,” 2020). Although ODNR maintains a vast archive of oil and gas records, there is a disclaimer on their oil and gas production database that does not guarantee the accuracy of the information provided. All of our wells are considered marginally producing wells, using the IRS definition of less than 15 barrels per day (5,475 barrels per year) for oil and 90 MCF per day (approximately 33,000 MCF annually) for gas production (Internal Revenue Service 2019; US Energy Information Administration 2018). All of the wells we sampled are in EIA’s lowest production rate bracket for marginal wells, 0–1 barrel of oil

equivalent/well/day. This is the most abundant type of oil and gas well in the United States, with over 325,000 wells in 2018 (US Energy Information Administration 2018). In addition, wells producing between 0 and 1 BOE are the most abundant category of well in Ohio, making our results likely representative of the full population.

Methane emission quantification

Upon arrival, components at the wellhead and pump-jack such as joints, fittings, valves, and vents at each well were screened using a Bascom Turner Gas-Rover, which detects CH₄ enhancements above 10 ppm. We did not make measurements at gathering lines, separators, or tanks. In some cases, components such as valves and vents that appeared to be closed were emitting CH₄. Some oil producing wells had open vents, such as where a gas gathering line would otherwise be attached for natural gas collection or to vent annular gas. These vents were quantified, so our measurements include intentional vents as well as leaks. The number of emission sources quantified at each well is included in Table 1, as whether the well was venting or not, where noted in our field notes.

When a component with a CH₄ concentration over 500 ppm was identified with the screening instrument, the emission rate was subsequently measured using an Indaco Hi-Flow sampler (Townsend-Small et al. 2016). When a well had no components that screened above 500 ppm, this well was assigned an emission rate of 0 g hr⁻¹, similar to EPA method 21 (United States Code of Federal Regulations (US CFR) 2017) and as in our previous work (Townsend-Small et al. 2016).

High-flow sampling has been used across the oil and gas supply chain to measure CH₄ emissions (Brantley, Thoma, and Eisele 2015; Lamb et al. 2015; Townsend-Small et al. 2016). The high-flow sampling technique uses a high-flow rate of air and a loose enclosure to completely capture the gas emitting from a source. Due to the loose enclosure, emitted gas is mixed with background air. The sampler measures concentrations of background air and the mixed air plus emitted gas, as well as the flow of the sample (emitted gas plus background air). Methane emissions are calculated using Equation (1), below. The Indaco device uses a vacuum pump, two Bascom Turner Gas Sentry instruments and a hot wire anemometer to measure the amount of CH₄ being emitted from each source (Howard, Ferrara, and Townsend-Small 2015; Lamb et al. 2015). One of the Gas Sentry instruments measures the CH₄ concentration of the sample plus background air, and the other measures the background air

Table 1. Well age, yearly production, CH₄ emission rate, and gas production of all active wells measured in Wayne National forest.

Well	Facility Age (years) ^a	2018 Oil production (bbls/yr) ^a	2018 Gas production (MCF/yr) ^b	CH ₄ Emission Rate (g/hr) ^b	Production normalized emissions (%) ^d	Noted maintenance issues	Number of emitting locations measured at well
1	36	0	0	0.0	0.0%	None	0
2	35	0	2584	0.0	0.0%	None	0
3	43	160	270	0.0	0.0%	Natural gas gathering line present	0
4	39	0	263	0.0	0.0%	Oil caked on wellhead	0
5	78	0	0	0.0	0.0%	Overgrown with weeds, rusty shaft, rocks used as ballast	0
6	17	4	0	0.0	0.0%	None	0
7	35	0	1388	0.0	0.0%	No leaks	0
8	68	125	0	0.0	0.0%	None	0
9	39	0	40	0.0	0.1%	None	1
10	33	214	0	0.1	>100%	Vent on side of wellhead. Well looks recently used and functional.	1
11	26	0	0	0.1	>100%	None	1
12	25	0	1109	0.3	0.0%	None	2
13	39	0	91	0.4	0.3%	Pumpjack appears inactive	2
14	35	0	374	2.3	0.4%	Leak at vent where gas gathering line should be	1
15	12	122	0	3.0	>100%	Leaking oil	2
16	35	0	106	3.2	1.6%	Rusty	5
17	31	0	166	3.6	1.3%	None	3
18	14	122	0	3.7	>100%	Well casing is covered in layers of gravel and oil soaked rags; tubing rigged up to vent up to top of the pumpjack	2
19	16	0	976	5.1	0.3%	None	2
20	69	125	0	5.1	>100%	None	1
21	39	3	0	6.5	>100%	Leak around entire well casing at ground level	2
22	35	77	270	13.8	3.0%	Venting from pumpjack, oil crusted around well casing	3
23	37	0	611	14.5	1.4%	None	3
24	37	0	106	17.1	9.4%	None	1
25	16	8	285	18.4	3.8%	Casing vent open. Oily casing and soil	1
26	35	0	0	18.9	>100%	Ground saturated with oil, high methane at well casing	1
27	37	0	0	21.8	>100%	Casing vent, well looks inactive	1
28	84	0	105	23.3	11.9%	Concrete around casing crumbling, oily smell	1
29	16	15	0	39.5	>100%	Shiny well shaft, oil all over ground	1
30	51	0	185	62.3	19.6%	None	1
31	37	76	1672	64.1	2.2%	None	2
32	29	0	1685	64.2	2.0%	Open valve on wellhead; oil spilled on well casing	3
33	15	5	0	69.2	>100%	Wooden well casing with high methane levels	4
34	16	8	0	69.5	>100%	None	1
35	17	6	0	86.2	>100%	Rusty shaft, wooden casing	1
36	35	77	0	100.0	>100%	Open vent, visible fumes, oily smell	1
37	16	124	0	200.2	>100%	Covered in vines and weeds. Open vent. Visible fumes and oily smell. Rusty.	1
38	6	0	285	223.1	45.6%	Audible and visible leak	4
39	16	8	0	228.8	>100%	Soil around wellhead is oily	1
40	50	12	0	311.5	>100%	Audible leak. Site appears in operation	1
41	20	0	1227	340.7	14.8%	Casing vent with tubing to vent gas near top of pumpjack	1
42	31	0	962	371.8	22.5%	None	2
43	16	15	0	404.1	>100%	No motor, soil is oily, appears abandoned	1
44	36	0	10	455.5	2434.4%	Rusty, venting to atmosphere	2
45	39	0	131	515.4	229.3%	None	6
46	35	0	1486	692.0	27.1%	Old infrastructure, tree fell on wellhead damaging and shifting well casing	1
47	22	303	0	759.8	>100%	Open vent, visible emissions, oily smell	1
48	23	88	0	906.7	>100%	Loud hissing sound from vent, audible from ~100 ft away. Fallen tree on wellhead during first visit	3

Notes. ^aProduction values and well age were obtained for each well from the Ohio Department of Natural Resources. Where original drilling or completion permits were unavailable, the first year of reported production was used to estimate the well age. ("Oil & Gas Well Production Numbers," 2020) ^bOne MCF = 19.17 kg CH₄ at 15.6 °C and 1 atm. ^cEmission rate is as measured in the current study and presented in Figure 1. Emission rates at wells 33, 40, 41, 46, and 48 are an average of all measurements. ^dProduction normalized emissions are calculated first by correcting annual gas production using the average CH₄ percentage from wellhead gas analyses in each study area (78.4% of total gas in the Marietta unit, 85.5% in the Athens unit). Production normalized emissions are reported as a percentage of total CH₄ corrected-natural gas production using the calculation (*methane emitted/methane produced*) * 100. Wells with an emission rate of 0 and a natural gas production of 0 were assigned a production normalized emission of 0%. Wells with >100% values had a positive emission rate and no reported gas production for the year in which they were sampled.

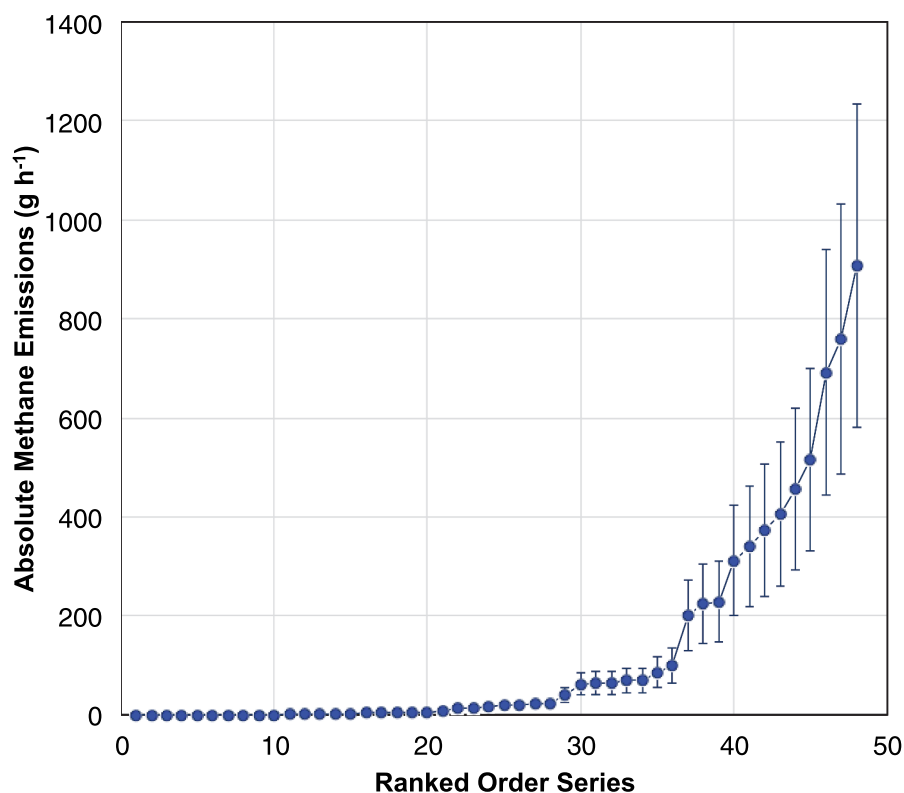


Figure 1. Ranked-order series of CH₄ emission rates from each well. The error bars represent the average normalized standard deviation of 36% and are based on all measurements taken from the high-flow instrument. Some wells were sampled more than once; these are presented as an average emission rate (Table 1, Figure 2).

only (Howard, Ferrara, and Townsend-Small 2015). Photographs of the screening and emission rate quantification techniques are provided in the supplemental information.

When the inlet of the high-flow sampler was positioned on an emitting component, a tarp attached to the inlet was draped over the source of CH₄ and loosely tightened to ensure all the gas was routed into the measurement system. To ensure the high-flow sampler was positioned properly, the Gas-Rover was placed in the outlet of the high-flow sampler. This practice allows for the operator to compare the screening values and outflow values to further ensure an accurate measurement.

A series of three CH₄ samples were collected at each measurement point from the outlet of the high-flow sampler via syringe and transferred into evacuated glass vials. The samples collected were analyzed by gas chromatography-flame ionization detection (GC-FID) at the University of Cincinnati. The CH₄ concentrations measured by the GC-FID were used to calculate the CH₄ emission rate at each emitting component. This method was chosen because both the Gas Rover and the Gas Sentry are designed to measure CH₄ in high CH₄ concentration

environments, such as distribution pipelines, and not in production gas environments where there are other hydrocarbons present. Sensors in these instruments have unknown response factors from non-methane hydrocarbons which make it difficult to correct the CH₄ concentrations measured by the Gas Rover and the high-flow (Connolly, Robinson, and Gardiner 2019; Howard, Ferrara, and Townsend-Small 2015). The GC-FID provides a concentration measurement for CH₄ only.

The CH₄ detectors on the Gas Rover and the high-flow sampler were calibrated daily on each day of use, using standards of 2.5% CH₄ and 100% CH₄. The flow velocity sensor on the high-flow sampler was also calibrated daily during use, using a four or five point calibration curve. Samples on the GC-FID were analyzed with bracketed standards, ranging from sub-atmospheric concentrations to 95% CH₄.

Whole-air samples

An additional focus of this study was to measure the emission rate of VOCs from marginal oil and gas wells. We took whole air samples at a subset of sampling sites

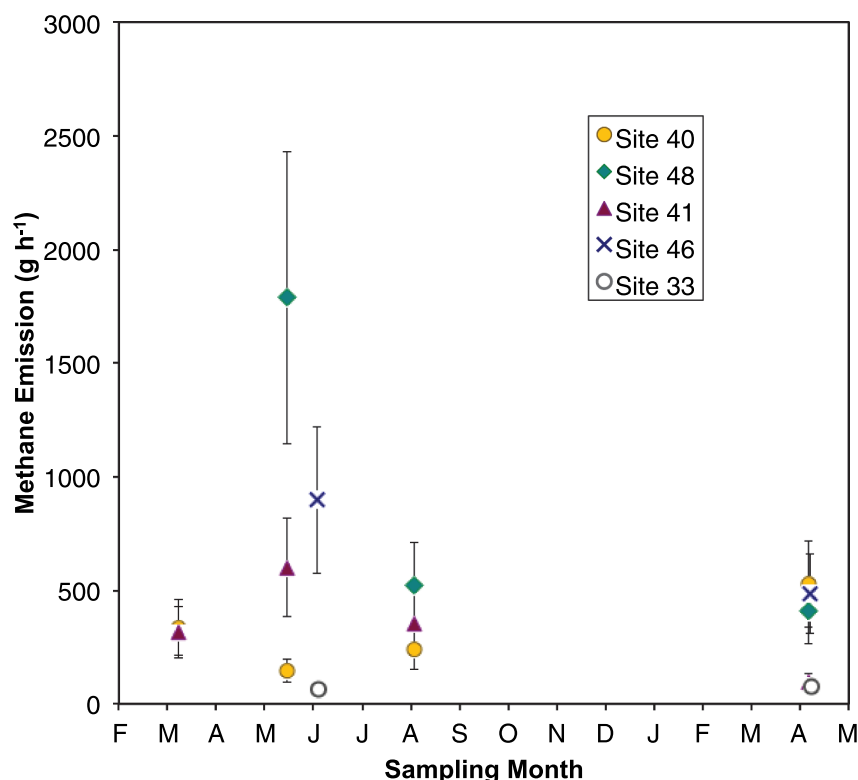


Figure 2. 13-month time series of CH₄ emissions from five wells where emission rates were measured more than once. Well numbers are as in Table 1 and Figure 1. Error bars represent the average standard deviation of all samples taken from the high-flow instrument of 36%.

($n = 16$) to determine the emission rate of VOCs that are known hazardous air pollutants (HAPs). 1–3 L evacuated stainless steel canisters without flow regulators were positioned to take samples in the outlet of the high-flow sampler (in the same location as the CH₄ sample collection) during emission rate measurement (Brantley, Thoma, and Eisele 2015). These samples were collected in conjunction with a CH₄ sample from the outlet of the high-flow sampler to establish a VOC:CH₄ ratio. This method provides a measurement with the assumption of no losses of VOCs throughout the sampler during passage through the sampler. Whole air samples were taken at the component with the highest screening value at each well. The whole air samples were analyzed according to EPA method TO-15. VOCs in ambient air including a variety of VOCs related to the oil and gas industry, such as the BTEX compounds, hexane, cyclohexane, and heptane (United States Environmental Protection Agency 1999). HAPs are defined by the U.S. Environmental Protection Agency as air pollutants that can cause cancer or have other impacts on human health. They may also be referred to as air toxics or toxic air pollutants (EPA 2017; US EPA 2015).

Data analysis

CH₄ emissions were calculated using Equation 1 (Howard, Ferrara, and Townsend-Small 2015)

$$\text{CH}_4 \text{ emission rate (kg/h)} = \frac{\text{flow}_{\text{high-flow sampler}} \times (\text{concentration}_{\text{sample}} - \text{concentration}_{\text{background}})}{\text{response factor}} \quad (1)$$

For this study, the value used for sample concentration was the concentration of CH₄ measured with GC-FID. The background concentration was measured by the Gas Sentry instrument in the high-flow sampler. Since CH₄ samples for GC analysis were taken at every measurement point, the response factor was assumed to be 1 for the GC, which only measured CH₄ and not any other non-CH₄ hydrocarbons.

VOC emission rates were estimated using the concentrations of VOCs measured in the whole air samples. Each whole air sample was taken in conjunction with a CH₄ sample, allowing the use of a VOC:CH₄ ratio to estimate a VOC emission rate. Following the equation presented in (Marrero et al. 2016), emission rates for each HAP measured were calculated as in Equation 2.

$$\begin{aligned} \text{VOC flux} &= \text{CH}_4 \text{ flux (g h}^{-1}\text{)} \\ &\times (\text{molecular weight VOC / molecular weight CH}_4) \\ &\times ([\text{VOC}] : [\text{CH}_4]) \end{aligned} \quad (2)$$

Because the TO-15 method analyzes for a variety of VOCs, the emission rates of each VOC detected in the whole air samples were calculated separately.

Production rates were obtained through the ODNR production database in order to calculate gas production-normalized emissions and assess the ratio of natural gas lost at each well. We took samples and measured the composition of wellhead gas in seven wells in the Wayne National Forest and used these data to convert the natural gas production rate to CH₄ production rate. The average gas composition for wells in the Marietta section was 78.4% CH₄ and the average gas composition for wells in the Athens section was 85.5% CH₄.

Error analysis

Each component was measured a total of three times during each visit. The error in our study-wide CH₄ emission rate measurement was estimated by averaging the standard deviation of the three CH₄ measurements with the mean emission rate for each measurement, for an average error of 36%.

Results and discussion

Methane emissions from marginal wells

Methane emissions from marginal wells measured in our study are shown in Figure 1. The error bars represent the average normalized standard deviation of the CH₄ emission rates derived from the CH₄ samples taken from the outflow of the high-flow sampler. We found a skewed distribution of CH₄ emission rates, indicating that only few of the wells measured are responsible for a majority of the emissions. Many of the wells ($n = 22$ out of 48) emitted 10 g h⁻¹ or less. Twenty-seven percent ($n = 13$) of the wells measured emitted over 100 g h⁻¹. The emission rates ranged from 0 g h⁻¹ to 907 g h⁻¹ with an average emission rate of 128 g h⁻¹ and a median emission rate of 18 g h⁻¹. The top four highest emitters, or 8% of the wells measured, were responsible for approximately 50% of the total CH₄ emissions observed in the study. This pattern of skewed distribution of CH₄ emissions has been found in previous studies of abandoned wells (Townsend-Small et al. 2016) as well as one previous study of active conventional wells (Omara et al. 2016) in the Appalachian Basin, and is characteristic of all natural gas systems nationally (Zavala-Araiza et al.

2015). The highest emitter in this study had an average emission rate of 906.7 g h⁻¹. The wellhead had been damaged by a fallen tree, the natural gas gathering line was not present, and a valve was opened to vent the natural gas being produced. This well was measured three times over the course of the study (see further discussion below).

The average CH₄ emission rate for marginal wells in this study was in the same order of magnitude as other conventional wells in Appalachia. Marginally producing conventional gas wells in Pennsylvania and West Virginia had an average emission rate of 820 g h⁻¹ (Omara et al. 2016); higher than our wells, although the wells in the current study had much lower oil and gas production rates than those measured by (Omara et al. 2016). The study by (Omara et al. 2016) used site-level measurement techniques that would include emissions from tanks, which we did not measure, and our results should be considered conservative for that reason. Our results are similar to the average emission rate of conventional oil and gas wells in West Virginia of 138 g h⁻¹, with production normalized emissions ranging from 0.02% to 56% from wells with an average gas production rate of 33,387 kg yr⁻¹ (Riddick et al. 2019). Although the wells we measured had the lowest rates of production nationally, and most were producing only oil or gas and not both, they had much higher CH₄ emission rates than abandoned wells. Unplugged abandoned wells in Appalachian Ohio emit CH₄ at an average emission rate of 28 g h⁻¹ (Townsend-Small et al. 2016). This is similar to the average emission rate for abandoned wells in Pennsylvania of 11 g h⁻¹ (Kang et al. 2014).

It is complicated to directly compare our results to measurements from higher producing hydraulic fracturing wells, because so many of our wells may be venting natural gas, whereas previous studies have been from hydraulic fracturing wells that are producing gas to pipelines. However, emission rates from marginal wells were lower than those reported from hydraulic fracturing wells. Unconventional wells in the Marcellus Shale were emitting CH₄ at an average of 18,800 g hr⁻¹, and at a much smaller proportion of production than conventional wells (0.01–1.2%) (Omara et al. 2016). A study of wells in the Barnett Shale found average emission rates of 630 g hr⁻¹ (Rella et al. 2015). Hydraulic fracturing wells in the Barnett, Denver-Julesburg, and Pinedale Basins had average emission rates of 1200, 504, and 2124 g hr⁻¹, respectively (Brantley et al. 2014).

The United States EPA developed an emission factor for active marginal wells based on model wells from a previous study of unconventional wells (Brantley et al. 2014). EPA estimates that marginal gas wells emit

4.8 tons of CH₄ per year (548 g CH₄ hr⁻¹) and that marginal oil wells emit 1.83 tons CH₄ per year (208 g CH₄ hr⁻¹) (United States Environmental Protection Agency 2018). ODNr does not distinguish between oil versus gas wells, but our average CH₄ emission rates were not different between wells that did and did not report an oil production rate for 2018. Our study sites are at the very lowest end of production rates for active wells nationally (0–1 BOE d⁻¹), whereas we assume that the EPA emission factor represents the entire production range of marginal wells (0–15 BOE d⁻¹), so this comparison is not straightforward. More field studies are needed to quantify CH₄ emission factors from the full production range of marginal wells.

Relationship with gas production

Previous studies in this region have shown that CH₄ emissions from natural gas wells have a predictable, positive relationship with gas production (Omara et al. 2016; Riddick et al. 2019). This relationship has also been used to scale national CH₄ emission rates from the production sector, including both conventional and unconventional wells (Alvarez et al. 2018; Omara et al. 2018). A recent synthesis including new data indicated that while newer, higher producing wells are a major source of CH₄ nationally, marginal wells may emit a much higher proportion of the gas produced (Omara et al. 2018). In the current study, out of the 48 wells visited, only 25 produced natural gas in 2018 according to the ODNr database, and the rest were either oil wells with a reported production rate of 0 for natural gas, or had no oil or gas production in 2018 (Table 1).

To explore the relationship between CH₄ emissions and natural gas production rates, we calculated production normalized emissions using the CH₄ emissions we measured in the field and annual natural gas production data for 2018 obtained from the ODNr production database (“Oil & Gas Well Production Numbers,” 2020). After correcting for CH₄ composition of natural gas, the overall mean CH₄ production rate for our wells was 612 g hr⁻¹, including wells with zero production. Using this average production rate, we can calculate a weighted average for all wells of total CH₄ emitted divided by total CH₄ produced of 21%. For wells with non-zero gas production rates (i.e., gas or oil and gas wells), the average production normalized emission rate was 117% (median: 2%, range: 0%–2434%). Two wells had production normalized emissions greater than 100%: one well had a CH₄ emission rate of 515 g h⁻¹ and an annual production rate of 131 MCF for 2018, for a normalized production rate of 229% (Table 1). Another well had a CH₄ emission rate of 455 g h⁻¹ and

an annual production rate of 10 MCF for 2018, for a normalized production rate of 2434% (Table 1). Without these two outliers, the average production normalized emission rate for gas wells was 7%. We also had 21 wells where we found a positive CH₄ emission rate and no recorded natural gas production for 2018 (i.e., oil wells). This includes our highest emitting well in the entire study (Table 1). These wells had a CH₄ emission rate ranging from 0.1 to 907 g h⁻¹. No production normalized emission rate can be calculated for these wells; a production normalized rate of >100% is assigned in Table 1. Finally, we also had four wells where we found no emissions and there was no gas production reported for 2018 in the ODNr database; for these wells, we assigned a production normalized emission rate of 0%.

Both of the previous studies of low producing conventional wells in Appalachia found a positive relationship between production rate and CH₄ emissions. A study conducted in West Virginia sampled at 74 wells but was only able to gather gas production data for 25 of them. Their average production normalized emission rate was 8.8% (range: 0.02–56%) (Riddick et al. 2019). Another study conducted in Pennsylvania and West Virginia found similar results to Riddick et al., with a median of 10.5% and range of 0.35–91% (Omara et al. 2016). Neither of these studies found CH₄ emissions that were greater than reported gas production at any well. Unlike in the previous studies, there was no correlation between the CH₄ emissions and annual production in our data, with many zero production numbers in our database ($R^2 = 0.003$). Because our wells had such low production rates, and many of our wells were found to be emitting more gas than producing and leaking oil (Table 1), the production rate data are somewhat less meaningful than for higher producing wells. Because of this, our “production normalized” emission rates should be interpreted with caution, as clearly the state production data do not represent all of the oil and gas coming from these wells.

We propose that the main driver of emissions from the wells visited is neglect. The state of maintenance at these wells was poor. Often, pumpjacks, tanks, and other infrastructure were rusty and sometimes appeared to have temporary fixes to just keep the well mechanically operational. When we noted maintenance problems at sampling sites, these are described in Table 1. Some wells looked like they had not been serviced in years. Sometimes, leaks were found at fittings and joints. We also found several wells with open valves that appeared to be for natural gas gathering lines. One well had a ~1 inch diameter hole in the casing near the base of the wellhead. Two of the wells had trees that had fallen on

the wellhead. In other cases, emissions were detectable via sight or smell at wellheads. Oil was sometimes present spilled on the ground or around well casings. Maintenance status had a significant effect on CH₄ emissions in our study ($p = .04$). At wells where poor maintenance was noted, the average CH₄ emission rate was 183 g h⁻¹, whereas at wells where we noted maintenance was good or no maintenance status was noted, the average CH₄ emission rate was 50 g h⁻¹ (see Table 1 for a description of maintenance at all study sites). While we note that our study did not aim to collect maintenance data at each well, and thus these calculations should be considered preliminary, the effect of maintenance status on CH₄ emissions, as well as the fact that many wells are venting gas and leaking oil (Table 1) may suggest that these wells are producing just enough oil or gas to keep them in the “active” category and forestall permanent abandonment, which requires expensive plugging within a certain amount of time. On the other hand, these wells may provide a minor but critical and steady amount of income to small operators in Appalachia, helped with tax offsets.

Are methane emissions episodic?

Most previous studies of CH₄ emissions from production sites have been based on single measurements, leading to questions about whether high emitters represent episodic events. In order to address this question, we visited some wells multiple times to assess whether CH₄ emissions are changing significantly over time. Figure 2 shows CH₄ emissions of five wells sampled between two and five times over 13 months. The error bars represent the average normalized standard deviation of all samples of 36%. We observed variation in CH₄ emissions over the study period, however, at no well did we observe an emission that appeared to be a one-time event. At some wells, CH₄ emissions decreased over time, including at our highest emitter, well 48, as well as at well 46 (Figure 2). At other sites, the emission rate varied overtime or increased (Figure 2).

The well with the largest decrease in emission rate was the largest emitter in our study (well 48, Figure 2, Table 1). This was the well-described above with the fallen tree on the wellhead and the open gathering line. In our second sampling visit (August 2018), we observed the tree had been cleared away, indicating at least some maintenance had been done on the well, but the open gathering line was still audibly emitting. Decreasing reservoir pressure due to venting may also be responsible for the decrease in emission rate observed at this well between the first and second measurement. Other wells did not exhibit significant differences in emission rate

between measurements. Environmental conditions such as temperature and pressure were incorporated into the flow calibration for the quantification of CH₄ emissions. Wind speed was addressed by isolating emissions with a plastic tarp.

Volatile organic carbon emissions

Figure 3 shows the distribution of VOC emissions for the top five VOCs emitted. Emission rates are also shown in Table 2, with the full suite of VOCs identified in the study found in Table S1. As with CH₄ emissions, there is a skewed distribution of VOCs with a few wells representing the majority of emissions (Figure 3). Hexane and heptane were the most abundantly emitted VOCs, with average emission rates of 902 and 704 mg h⁻¹, respectively (Figure 3, Table 2). This was followed by cyclohexane, toluene, and benzene, with average emission rates of 246, 68, and 50 mg h⁻¹, respectively (Figure 3). Emission rates of VOCs did not follow the same distribution of CH₄ emissions, as the highest CH₄ emitter, well 48, was not the highest emitter of VOCs (Figure 3). As seen in Figure 3, each gas well had a different VOC emission profile. As with CH₄ emissions, we also did not see a relationship of VOC emissions with oil or gas production rate.

Other studies have measured VOC emission rates from unconventional oil and gas wells and found higher rates of VOC emissions, although these wells are also larger sources of CH₄ and produce oil and gas at rates many orders of magnitude larger than the ones in the current study. For example, the average benzene flux from individual unconventional wells in the Barnett Shale was 4.9 g h⁻¹ (Marrero et al. 2016), compared to an average flux from marginal wells in the current study of 50 mg h⁻¹ (Table 2). However, similar to the current study, the most abundantly emitted VOC from wells in the Barnett Shale was hexane (Marrero et al. 2016). Unconventional wells in the Denver-Julesburg Basin also emit VOCs at higher rates than marginal wells, from 72 to 8352 g h⁻¹ (Brantley, Thoma, and Eisele 2015). The whole air samples collected in this study were tested for several PAHs, however, none were detectable, unlike in previous studies that sampled adjacent to unconventional wells in Ohio (Paulik et al. 2016).

Despite the relatively low emission rates found here, these sources may still pose a significant risk to those exposed, especially if marginal wells are on or near residential property and lead to long-term exposure; a particular danger given the large number of marginal wells in Appalachia and nationwide. For example, proximity to low producing and inactive wells in urban areas can affect birth outcomes in pregnant women (Tran

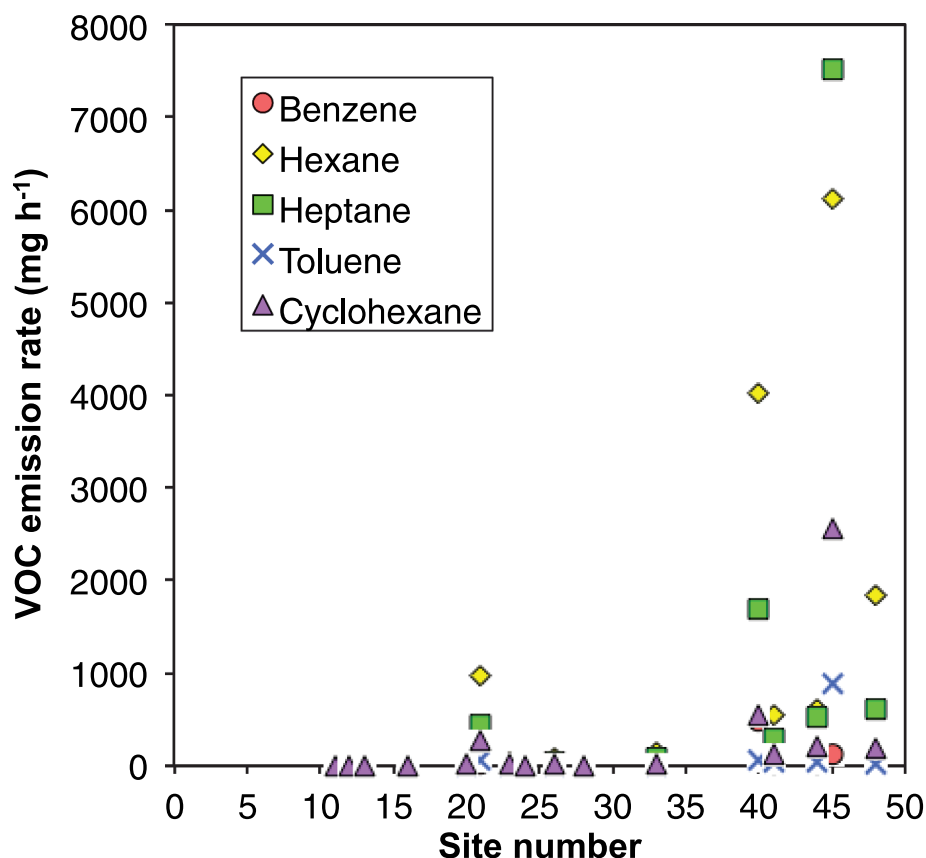


Figure 3. Emission rate of the five most abundantly emitted VOCs (mg h^{-1}). Well numbers are the same as in Table 1 and Figure 1.

Table 2. Range of VOC emissions found in the current study. Well numbers are the same as in Table 1. Top five most abundantly emitted VOCs are shown. Data are also shown in Figure 3. The full suite of VOC emissions found in this study can be found in Table S1.

Well number	Benzene Emission Rate (mg h^{-1})	Hexane Emission Rate (mg h^{-1})	Heptane Emission Rate (mg h^{-1})	Toluene Emission Rate (mg h^{-1})	Cyclohexane Emission Rate (mg h^{-1})
11	0	0	1	0	0
12	0	1	1	0	0
13	0	3	1	0	0
16	1	16	7	0	2
20	0	4	10	0	17
21	25	970	446	51	264
23	1	49	18	2	10
24	0	22	11	1	4
26	3	75	33	2	27
28	0	8	3	0	2
33	1	145	80	1	18
40	492	4021	1683	69	550
41	28	554	299	29	127
44	25	617	533	35	210
45	134	6117	7526	884	2564
48	92	1830	619	13	195

et al. 2020). Holes in well casings, as noted in a few cases in Table 1, could lead to aquifer contamination: an additional hydrocarbon exposure pathway for residents of rural areas who rely on groundwater as their only water source (Botner et al. 2018; Osborn et al. 2011). We also noted some wellheads where brine appeared to have spilled from vents, which could pose a hazard to human

and ecosystem health. Another serious consequence of our results is for oil and gas field workers, who will be exposed to high levels of VOCs at wells that are venting. Although we observed at least two wells where vents were routed up above inhalation level using tubing, in other cases, venting was at ground level or on the well-head (Table 1). Acute exposure to VOCs can cause

serious harm in oilfield workers, including sudden death (Harrison et al. 2016). These high emitting wells also present an explosion risk to workers.

Some VOCs and HAPs, like benzene and the other BTEX compounds, can lead to chronic diseases such as leukemia and other cancers, neurological damage, birth defects, and hearing loss (Garcia-Gonzalez et al. 2019; McKenzie et al. 2012). In this study, the most abundant HAPs measured were heptane and hexane. Inhalation of hexane, for example, can cause neuropathy and other neurological effects (US EPA 2013). Acute exposure of heptane can lead to dizziness, nausea, and dermatitis, among other symptoms (CDC 2018). Emissions of VOCs from marginal wells may also impact human health indirectly through the formation of tropospheric ozone (Pekney et al. 2014). The level of risk from these marginal wells would depend on the ambient concentration and the exposure time, as well as the emission rate of the toxic chemical from the well in question. As previously noted, the highest risk may be to workers who routinely come in close contact with high emitting wells (Esswein et al. 2014; Goldstein et al. 2014; Harrison et al. 2016).

Policy implications

Marginal natural gas wells on federal land in Ohio are emitting a significant portion of natural gas produced, and many oil wells are venting 100% of natural gas produced. There are hundreds of thousands of these marginal “stripper” wells in the United States. The results of this study indicate that, despite the lower absolute emission rates we have found relative to unconventional wells, these marginal wells may be a nationally significant source of CH₄. Scaling our results to a national level is a challenge. Previous studies have used the relationship of CH₄ emission rate with gas production for scaling-up, but we found no such relationship. We also found no relationship of CH₄ emissions with well age. Multiplying our average emission factor for marginal wells in the 0–1 BOE well⁻¹ d⁻¹ category by the total number of wells in this category (336,012 in 2018) (US Energy Information Administration 2018) gives an annual emission rate of 0.4 ± 0.1 Tg CH₄ yr⁻¹; this is about 11% of total CH₄ emissions from oil and gas production in the EPA GHG inventory and 5% of CH₄ emissions from the production sector in a recent synthesis of measurement campaigns (Alvarez et al. 2018). According to EIA, marginal wells in the 0–1 BOE d⁻¹ category produced only 0.2% of annual oil production and 0.4% of annual natural gas production in 2018 (US Energy Information Administration 2018), indicating that wells in this category are a disproportionate source of CH₄. Future work

may consider measurements in additional production rate brackets and regions to create national emissions factors (US Energy Information Administration 2018), as well as measurements from oil storage tanks at marginal wells, as these tanks may have similar maintenance issues to those noted at wellheads.

Mitigating emissions from just one category of stripper wells (0–1 BOE d⁻¹) could reduce CH₄ emissions from the oil and gas supply chain by up to 5% to 10% with an extremely minor impact on domestic energy supply. This shortfall in oil and gas supply could be eliminated by drilling a much smaller number of new unconventional wells, which emit CH₄ at lower proportions (Omara et al. 2016). There may be a large number of stripper wells on public land, and these could be a preliminary target for mitigation, with concomitant air quality and recreational benefits (Pekney et al. 2014; Ratledge, Davis, and Zachary 2019). Regular maintenance may be one way to prevent the loss of natural gas and emissions of VOCs from marginal wells. Regulation of marginal wells such as leak detection and repair or requiring flaring instead of venting may help mitigate emissions. Over the past decade, the contribution of marginal wells to regional and national oil and natural gas supply chains has sharply declined (US Energy Information Administration 2018); therefore, another mitigation pathway for these emissions may be permanent plugging, which sharply decreases CH₄ and VOC emissions (Townsend-Small et al. 2016) and may also create jobs. Because these emissions may be relatively easy to mitigate and may represent a substantial portion of national emissions from oil and gas production, this is an important area for future research and regulation.

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Disclosure statement

No potential conflict of interest was reported by the authors.

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EDF'S EXHIBIT ZZ

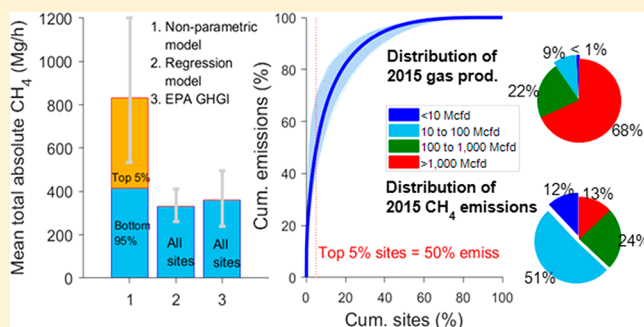
Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate

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Supporting Information

ABSTRACT: We used site-level methane (CH_4) emissions data from over 1000 natural gas (NG) production sites in eight basins, including 92 new site-level CH_4 measurements in the Uinta, northeastern Marcellus, and Denver-Julesburg basins, to investigate CH_4 emissions characteristics and develop a new national CH_4 emission estimate for the NG production sector. The distribution of site-level emissions is highly skewed, with the top 5% of sites accounting for 50% of cumulative emissions. High emitting sites are predominantly also high producing (>10 Mcfd). However, low NG production sites emit a larger fraction of their CH_4 production. When combined with activity data, we predict that this creates substantial variability in the basin-level CH_4 emissions which, as a fraction of basin-level CH_4 production, range from 0.90% for the Appalachian and Greater Green River to $>4.5\%$ in the San Juan and San Joaquin. This suggests that much of the basin-level differences in production-normalized CH_4 emissions reported by aircraft studies can be explained by differences in site size and distribution of site-level production rates. We estimate that NG production sites emit total CH_4 emissions of 830 Mg/h (95% CI: 530–1200), 63% of which come from the sites producing <100 Mcfd that account for only 10% of total NG production. Our total CH_4 emissions estimate is 2.3 times higher than the U.S. Environmental Protection Agency's estimate and likely attributable to the disproportionate influence of high emitting sites.



INTRODUCTION

Natural gas (NG) extracted from shale and tight oil reservoirs has transformed the U.S. energy landscape resulting in rapid increases in total NG production and consumption.¹ While NG combustion emits less than half the carbon dioxide (CO_2) of other fossil fuels,² it is primarily composed of methane (CH_4), which produces 86 times more radiative forcing than CO_2 over a 20-year time frame.³ Therefore, CH_4 emitted from the NG system represents wasted resources, lost revenue, and erodes the potential climate benefits of NG relative to other fossil fuels.

There has been a major effort over the last five years to quantify CH_4 emissions from the oil and NG supply chain. Dozens of recent measurement-based studies^{4–32} have exposed the magnitude and scope of the CH_4 emissions problem, highlighting the following common themes: (i) Government inventories often significantly underestimate CH_4 emissions, (ii) a small fraction of high-emitting sites or sources account for a disproportionately large fraction of total CH_4 emissions, and (iii) there are significant basin-to-basin differences in production-normalized CH_4 emissions (i.e., CH_4 emissions expressed as a fraction of CH_4 produced).

We focus on CH_4 emissions from NG production sites. The U.S. EPA³³ attributes two-thirds of the 6.5 Tg of total CH_4

emissions from the NG supply chain to the NG production sector, which includes 2 Tg of CH_4 emissions associated with NG production from more than 400 000 NG wells. Herein, we define NG production sites to include any NG-producing well pad with one or more wellheads and ancillary surface equipment (e.g., NG separators, pneumatic pumps/controllers, and/or storage vessels). Such onsite processing equipment are often significant sources of elevated CH_4 emissions.^{4,8,29} These high emissions are often the result of abnormal process conditions (e.g., equipment malfunctions); they can be persistent or episodic and are difficult to predict.^{4,27–29} The stochastic characteristics of high-emitting sites appear to contribute, at least in part, to the orders-of-magnitude variability in measured absolute site-level CH_4 emissions (Figure 1). Furthermore, top-down aircraft studies report widely varying estimates of basin-level, production-normalized CH_4 emissions.^{19–24} The causative factors for site- and basin-level variability in CH_4 emissions are not well-understood. It has been suggested that differences in the composition of the

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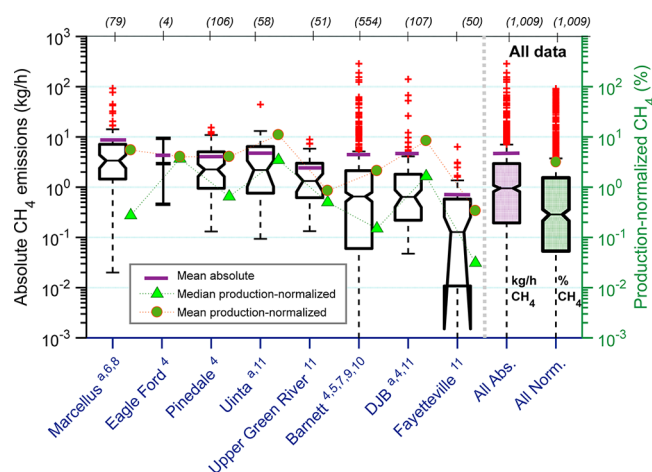


Figure 1. Site-level measurement data synthesized in this study. Numbers in parentheses indicate the number of sites with emissions data for each basin; the citations to the original studies are indicated as superscripts after basin names. New measurements are indicated with an (a) in the Denver-Julesburg (DJB; $n = 18$, or 17% of all DJB sites), Marcellus (NE PA unconventional sites, $n = 45$, or 57% of all Marcellus data), and Uinta ($n = 29$, or 50% of all Uinta sites). The boxes represent the 25th and 75th percentiles, while the whiskers extend to $1.5\times$ the interquartile range, and values outside this range are the outliers, marked with red crosses. The black horizontal line inside each box represents the median while means are shown in purple. The notches visually depict the 95% confidence interval on the median. For Eagle Ford, measurement data for the four sites are represented with an error bar indicating the minimum and maximum. For Fayetteville, the notch extends beyond the 25th percentile as a result of the sample size and the data spread in this basin. “All Abs.” and “All Norm.” represent combined data set for all absolute and production-normalized CH_4 emission rates ($n = 1009$), respectively.

extracted NG (e.g., dry versus wet gas), operator practices, and/or differences in NG production rates may be important.^{11,24,29} Additionally, several states have recently proposed or enacted oil and NG CH_4 regulations,^{34–38} which may yield pronounced differences in future regional/basin-level CH_4 emissions when compared against regions/basins without similar regulatory actions.

To better understand CH_4 emissions among NG production sites and across multiple basins, we compiled and analyzed recently measured site-level CH_4 emissions data for more than 1000 NG production sites in eight U.S. basins^{4–11} (Figure 1). We use this large data set of site-level CH_4 emissions (both absolute and production-normalized emissions) and site-level NG production to test the hypothesis that there are no significant basin-to-basin differences in the distribution of site-level CH_4 emissions and that, on average, site-level emissions correlate with their NG production characteristics. We then combine these site-level CH_4 emissions data with a national database on NG production site characteristics (i.e., site-level NG production rate) to estimate (i) total CH_4 emissions from U.S. NG production sites, (ii) major sources and distributions of CH_4 emissions, including CH_4 from high-emitting sites, and (iii) variability in CH_4 emissions among basins.

MATERIALS AND METHODS

Overview of Site-Level Measurement Data. We analyzed measured site-level CH_4 emissions data from 1009 NG production sites located in eight different basins. This includes recently published data from eight independent

studies,^{4–11} supplemented with new data for 92 additional sites sampled in the Denver-Julesburg (DJB), Uinta, and Marcellus (northeastern PA, Figure 1, Supporting Information (SI) Section S1). These new measurements targeted production regions with unique site-level production characteristics, that is, unconventional dry gas production sites with high site-level production rates in northeastern Marcellus and low-producing, mixed oil and gas sites in Uinta and DJB. The new measurement data help diversify site-level production characteristics and measured production regions/basins in the consolidated data set.

We focus on routinely producing sites with known NG production and assumed that measured CH_4 emissions resulted from routine operations (e.g., equipment leaks, venting from pneumatic controllers and storage tanks) or were unplanned (e.g., unintended emissions from malfunctioning equipment). Thus, the combined data set does not include CH_4 emissions from completion flowback⁸ or liquids unloadings.¹¹ Additionally, site-level CH_4 emissions rates were unavailable for storage or coalbed CH_4 well sites, and emissions from these sites were not assessed in the present study. For measured sites with reported NG production rates, the CH_4 measurements were performed between 2010 and 2016 and used a variety of onsite and downwind ground-based site-level CH_4 measurement techniques that can be broadly grouped into three categories:

- Direct onsite measurements (henceforth, “onsite measurements”), which involved optical gas imaging for leak identification followed by direct quantification of all identified leaks.⁵ These component-specific measurements are then summed to estimate site-level emission rate. Onsite measurements accounted for 28% of all site-level measurement data.
- Downwind tracer flux (TF) measurements of downwind plumes of CH_4 and intentionally released tracers (e.g., acetylene and nitrous oxide).^{6,8} TF sites accounted for 6.7% of the total data.
- Downwind CH_4 plume measurements combined with inverse Gaussian modeling. This includes both downwind stationary measurements using EPA’s Other Test Method (OTM-33A^{4,11}), and downwind mobile measurements followed by Gaussian modeling (MM-Gaussian^{7,9,10}). Sites sampled using these techniques accounted for 65% of the total sites.

There are limitations with each method. For example, onsite measurement (method (a)) requires site access and proper operation and performance of both the plume imaging (for leaks survey) and leak rate measurement devices.^{5,39} Even with site access, some onsite emission sources may be present at locations that are not safely accessible for leak rate quantification (e.g., see Subramanian et al.¹⁶). Additionally, all stationary and mobile downwind measurements require sites with downwind road access and favorable meteorological conditions. These measurement methods have different uncertainties, which range from approximately $\pm 20\%$ to $\pm 60\%$ (TF and OTM-33A) to a factor of 3 for the MM-Gaussian approach.^{4–11}

We use the site-level production-normalized CH_4 emissions as reported by Robertson et al.¹¹ and Omara et al.⁸ For Rella et al.,¹⁰ Yacovitch et al.,⁹ and Lan et al.⁷ we use the site-level CH_4 emissions, NG production, and production-normalized CH_4 emissions as consolidated and reported by Zavala-Araiza et

Table 1. Ten NG Production Bins Used in the Nonparametric Model (Developed Based on Deciles of NG Production for the Measured Sites) And Their Estimated Mean Site-Level Production-Normalized CH₄ Emissions

production bin (Mcf/d)	<0.4–31	31–73	73–147	147–254	254–390	390–616	616–1047	1047–1699	1699–3342	>3342
no. measured sites ^a	101	101	101	101	101	101	101	101	101	100
national sites (%) ^b	65%	15%	8.3%	3.9%	2.1%	1.7%	1.4%	0.90%	0.83%	0.81%
national prod. (%) ^c	3.2%	4.2%	5.2%	4.5%	3.97%	4.9%	6.7%	7.2%	11.7%	48.4%
mean (% CH ₄) ^d	20	5.4	2.8	1.6	1.9	1.4	0.89	1.2	0.23	0.17
lower bound on mean (% CH ₄)	16	3.3	1.6	1.1	0.96	0.7	0.38	0.45	0.14	0.12
upper bound on mean (% CH ₄)	25	7.9	4.4	2.2	3.3	2.5	1.7	2.2	0.34	0.24

^aDenotes the number of measured sites in each production bin (total = 1009). ^bTotal U.S. NG production sites = 498 000. ^cNG production for these 498 000 sites was 83 billion cubic feet per day (Bcf/d). ^dThe mean production-normalized CH₄ emission rate in each bin was obtained by randomly drawing, with replacement, an emission rate from the empirical distribution until a randomly sampled emission rate was assigned to each of the sampled sites. This was repeated 10 000 times and the mean obtained from the average of averages of each simulation, while the 2.5th and 97.5th percentiles characterized the lower and upper bounds on the mean, respectively (SI Figure S18).

al.²⁹ For onsite measurements in the Barnett,⁵ we calculated site-level production-normalized CH₄ emissions based on the study's reported site-specific CH₄ mole fraction in NG and site-level NG production; sites without NG production rates were excluded from this analysis. For Brantley et al.⁴ and measurements performed as part of the present study, we estimated site-specific production-normalized CH₄ emissions based on the average county-specific or region-specific CH₄ mole fractions from the EPA's Oil and Gas Tool.⁴⁰

We excluded data for eight sites with production-normalized CH₄ emissions >100%. These eight sites were sampled offsite using the downwind plume measurements approaches utilizing Gaussian plume inverse modeling. It is possible that the measured CH₄ emissions exceeding 100% of CH₄ production was due to offsite CH₄ sources (e.g., biogenic CH₄ source, CH₄ from collocated equipment such as abandoned well, etc.). The exclusion of these eight sites from the consolidated data set does not change our results: if we include them in our analysis, the total production CH₄ emissions increases by <7%, well within the overall 95% confidence interval.

Overall, the 1009 measured sites were located in the Barnett ($n = 554$ sites), Denver-Julesburg (DJB, $n = 107$), Pinedale ($n = 106$), Marcellus ($n = 79$), Uinta ($n = 58$), Upper Green River ($n = 51$), Fayetteville ($n = 50$), and Eagle Ford ($n = 4$) basins (Figure 1). Site-specific NG production rates ranged from 0.4 Mcfd (1 Mcfd = 1000 cubic feet per day) to 78 000 Mcfd. Analysis of production data from Drillinginfo⁴¹ (further description below) indicates that in 2015, 94% of U.S. NG production sites had site-level NG production rates that fell within this range. Additional site information (e.g., number of wells onsite, gas processing and emissions control equipment in use, conventional or unconventional well type, and site age) were generally unavailable or not reported.

National Activity Data. We used well-level NG production data reported by Drillinginfo (DI Desktop⁴¹), a commercial platform that aggregates publicly available and proprietary well-level data, including monthly NG production, first reported production date, drilling configuration, operator name, and location. Using geospatial analysis with ArcGIS, we aggregated well-level information into site-level (well-pad) information (see SI Section S2). In total, 498 000 NG producing well pad sites were identified, with total 2015 NG production of approximately 27 Tcf (trillion cubic feet). As of March 2017, Drillinginfo did not report 2015 well-level production data for wells in Kentucky, Tennessee, Missouri, Oregon, Illinois, and Indiana. These states were not included in our analyses. The EIA⁴² estimates that these states

contributed <0.5% of total national NG production. Using the EPA's county-specific and basin-specific estimates of mean CH₄ content in NG,⁴⁰ we estimated total CH₄ production of 23 Tcf from these sites in 2015. The distribution of sites based on their NG production characteristics is shown in Table 1.

Extrapolation of Measured Site-Level Emissions to Total Population of Sites. We used two methods for extrapolating the measured site-level CH₄ emissions to the total population of sites: (i) a robust regression model, and (ii) a nonparametric model. These two approaches allow us to explore the influence of high-emitting sites on predicted total CH₄ emissions; whereas the first approach downweights their contribution, the second approach fully incorporates them. As described further in detail below, both of these approaches utilize the site-level production-normalized CH₄ emissions data. In the first approach, we estimated site-level CH₄ emissions for each of the 498 000 NG production sites in 2015 by fitting a robust weighted least-squares quadratic regression model of the production-normalized CH₄ emission as a function of NG production. The robust fit was performed using a MATLAB Statistics Toolbox algorithm that uses an iteratively reweighted least-squares approach with a bisquare weighting function,⁴³ $wfun(wfun = (abs(r) < 1) \times (1 - r^2)^2; r = resid/(tune \times s \times (1 - h)^{0.5}); s = \frac{1}{0.6745} \times \text{median absolute deviation of the residuals (resid) from the median}; h \text{ is a vector of leverage values for the least-squares fit and tune is a tuning constant} = 4.685)$. Thus, for each site, its production-normalized CH₄ emission rate (%) was estimated based on the fit obtained from the robust regression, which is a function of the site's NG production rate. The site's absolute CH₄ emission rate (kg/h) was then calculated by multiplying its production-normalized CH₄ emission rate with its CH₄ production rate.

In the second approach, we estimate site-level CH₄ emissions using nonparametric bootstrap resampling methods in order to adequately characterize the asymmetrical distributions of the empirical data. We first developed 10 empirical production-normalized CH₄ emissions distributions by grouping measured emissions into 10 bins based on deciles of NG production for the 1009 sites with emissions data (Table 1). We then grouped all 498 000 U.S. NG production sites into the same 10 bins based on the measured site-level NG production deciles. Among sites with emissions data, the site-level NG production rates ranged from 0.4 Mcfd to 78 000 Mcfd; however, among the total population of U.S. NG production sites, site-level NG production ranged from 0.001 Mcfd to 138 000 Mcfd (SI Figure S21). In grouping the

national population of sites, the 28 900 sites (5.8% of all sites) producing <0.4 Mcfd were placed in the same bin as the sites producing 0.4 to 31 Mcfd, which describes the first decile. Similarly, the six sites (0.0012% of all sites) that produced >78 000 Mcfd were placed in the last bin as the sites producing 3342 to 78 000 Mcfd. As shown in Table 1, the mean production-normalized CH₄ emissions in each bin decreases consistently with increases in site-level NG production. Our analysis shows that this grouping for national sites with NG production outside of the measured production is robust: if, for example, sites producing <0.4 Mcfd were assigned a production-normalized CH₄ emissions of 100%, the resulting national CH₄ emissions would increase by only 0.33%. Furthermore, we find that the distribution of site-level NG production rates for the sampled sites is statistically similar to that for the national population of sites across all production bins, except for the low production sites in the first bin which are undersampled (SI Figure S17).

For each site in each production bin, we estimate its site-level CH₄ emissions (kg/h/site) by randomly drawing, with replacement, a production-normalized CH₄ emission rate from the bin-specific empirical distribution. We then multiply this randomly sampled production-normalized CH₄ emission rate with the site-specific CH₄ production rate, repeat this process for every site, and then sum across all sites. We repeat this simulation 5000 times for each site in order to estimate the mean total CH₄ emissions; the 2.5th and the 97.5th percentiles were then used to characterize the 95% confidence interval on mean total CH₄ emissions.

Our overall estimated uncertainty on mean total CH₄ emissions, obtained from the 2.5th and 97.5th percentiles based on the nonparametric resampling, was +40%/−36% and was dominated by variability in mean site-level CH₄ emissions. These are influenced by study-specific sample sizes, site representativeness, and/or method accuracy. There are also uncertainties associated with activity data from Drillinginfo⁴¹ but they are difficult to quantify as these data are aggregated from publicly available sources that may be subject to reporting errors. These uncertainties include uncertainties in well location and production data. All Drillinginfo data were used as reported without any modifications. Finally, there are uncertainties associated with county/basin-level CH₄ mole fractions from the EPA's Oil and Gas Tool.⁴⁰ However, the impact of these uncertainties on estimated total CH₄ emissions are expected to be small. For example, in the Appalachian Basin, we used an average CH₄ content of 83%.⁴⁰ Increasing this to 95% or decreasing it to 75% yields results that are within 15% of the mean estimated total CH₄ for this basin, well within the overall method uncertainty of +40%/−36%.

Two-Sample Kolmogorov–Smirnov Tests. We compared the distributions of site-level absolute and production-normalized CH₄ emissions among different basins using the two-sample Kolmogorov–Smirnov (K–S) test, with significance established at $p < 0.01$. These statistical comparisons were performed using MATLAB.

RESULTS AND DISCUSSION

Variability in Empirical Site-Level and Basin-Level Methane Emission Rates. Figure 1 shows that both the absolute and production-normalized CH₄ emission rates are highly variable. Nearly three-quarters (74%) of sites exhibited site-level CH₄ emissions between 0.1 and 10 kg/h but, overall, site-specific absolute CH₄ emission rates varied by more than 5

orders of magnitude, ranging from 0 to 300 kg/h. There are basin-to-basin differences in emissions with mean basin-specific absolute CH₄ emission rate ranging from 0.61 kg/h/site (95% confidence interval, henceforth CI: 0.33–0.95) to 7.9 kg/h/site (CI: 4.9–12) in the Fayetteville and Marcellus basins, respectively. The overlap, or lack thereof, in the length of the boxplot notches in Figure 1 suggests basins cluster into three groups with statistically different measured median absolute CH₄ emission rates: (i) A group of basins with high site-level emissions: Marcellus (median = 3.4 kg/h/site), Pinedale (2.3 kg/h/site), Uinta (2.2 kg/h/site); (ii) A group of basins with moderate site-level emissions: Barnett (0.65 kg/h/site) and Denver-Julesburg (DJB) (0.64 kg/h/site); and (iii) Fayetteville, with low site-level emissions (0.13 kg/h/site). The Upper Green River basin falls between the high and moderate emissions groups with a median emissions of 1.3 kg/h/site.

Site-specific production-normalized CH₄ emission rates ranged from 0% to 91%, while the mean basin-specific production-normalized CH₄ emission rates ranged from 0.34% (CI: 0.07–0.74%) to 11% (CI: 6.9–16%) in the Fayetteville and Uinta, respectively (SI Table S8). Within 95% confidence intervals, four groups of basins have measured median production-normalized CH₄ emissions that are statistically different (SI Figure S19): (i) DJB (median = 1.6%) and Uinta (3.5%) have high production-normalized emissions; (ii) Marcellus (0.27%), Pinedale (0.65%), and Upper Green River (0.50%) have moderate production-normalized emissions; (iii) Barnett (0.15%) and (iv) Fayetteville (0.031%) both have low emissions. Thus, at the basin level, the measured mean or median site-level production-normalized CH₄ emissions vary by one to 2 orders of magnitude, while the measured mean or median site-level absolute CH₄ emissions vary by at least an order of magnitude.

Comparison of Empirical Site-Level Methane Emissions Distributions among Basins. Figure 2 shows the empirical cumulative distributions of both the absolute and production-normalized CH₄ emissions sorted by basins. The site-level emissions are highly skewed; for example, among all sampled sites in the Barnett, the top 5% of high-emitting sites accounted for 66% of cumulative absolute CH₄ emissions. The skewness of CH₄ emissions distributions are determined, in part, by the sample size.¹⁸ A concern is representativeness of the sample population, including the magnitude and frequency of extreme emitters.⁴⁴ Representative distributions are difficult to capture in part because of the stochastic characteristics of site-level CH₄ emissions and the logistical limitations of common site-level measurement techniques (see Materials and Methods). To compare CH₄ emissions distributions among basins, we attempted to control for these potential sampling artifacts by stratifying basin-specific CH₄ emissions based on the median site-level NG production rate (390 Mcfd) and, in each group, limiting our comparison to only include basins with $n \geq 50$.

We used the two-sample Kolmogorov–Smirnov test (i.e., six paired tests for the <390 Mcfd group and three paired tests for the >390 Mcfd group) to compare the different basin-specific emissions distributions shown in Figure 2 (SI Table S13). The absolute CH₄ emissions distributions are generally statistically different among basins at the 1% significance level (Figure 2a). Indeed, the two-sample K–S test suggests only the absolute site-level CH₄ emissions distributions for the <390 Mcfd sites in the Pinedale and Uinta basins came from similar continuous distributions ($p = 0.24$).

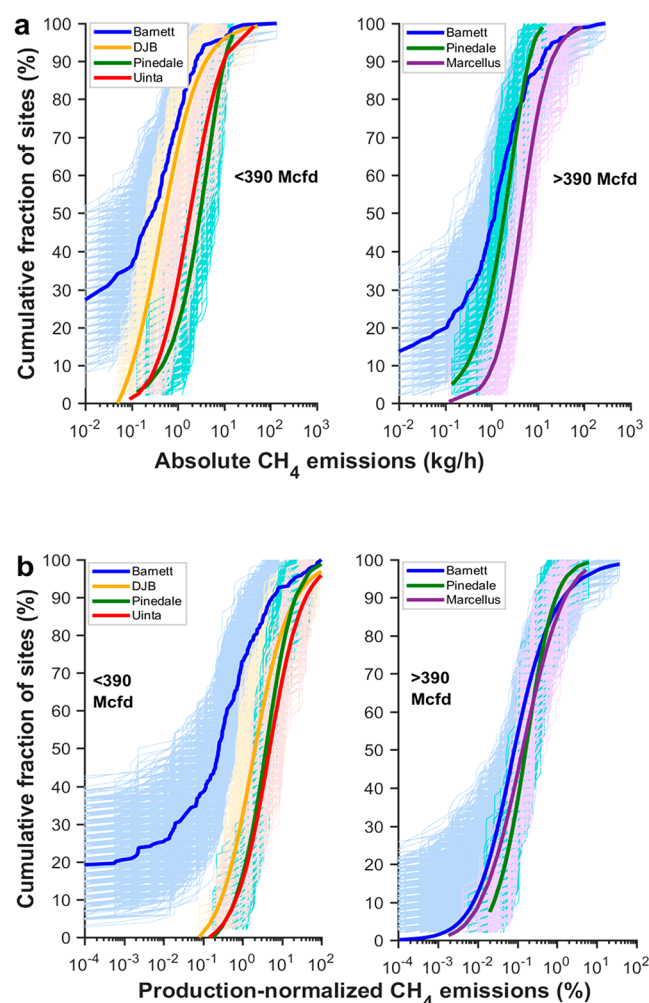


Figure 2. Comparison of CH₄ emissions distributions among basins. (a) absolute and (b) production-normalized emissions. Only basins with $n \geq 50$ sites were evaluated. For the <390 Mcfd bin, comparisons were made among the Barnett ($n = 245$), DJB ($n = 95$), Pinedale ($n = 50$), and Uinta ($n = 50$) Basins. For the >390 Mcfd bin, comparisons were made among the Barnett ($n = 309$), Pinedale ($n = 56$), and the Marcellus ($n = 57$) Basins. The lightly colored lines indicate the 10 000 bootstrap distributions obtained by randomly sampling 50 sites, with replacement, from the empirical distributions (shown in bold solid lines). Differences in distributions were assessed using the 2-sample Kolmogorov–Smirnov test with significance established at $p < 0.01$.

In contrast, the distributions of production-normalized CH₄ emissions were generally statistically similar among all paired basins ($p > 0.01$, SI Table S13), except for the Barnett sites producing <390 Mcfd (Figure 2b). The Barnett data for the <390 Mcfd sites are skewed low compared to the other basins partly because 20% of all the sampled sites in this bin had nondetectable emissions,¹⁰ and nearly one-third were obtained from short-term onsite measurements.⁵ The sites with reported zero emissions were sampled using mobile downwind plume measurements but had no independent measure to verify sites with undetectable plumes (e.g., the use of an intentionally released tracer from the site). Additionally, component-level measurements,⁵ which are typically completed in minutes, may be biased low as periodic emission events (e.g., tank flashing) may be missed. Given this uncertainty, it is possible that high-emitting sites are underrepresented among sites producing

<390 Mcfd in the Barnett, thus increasing the uncertainty in the scaled-up CH₄ emissions. This potential sampling artifact was not observed among sites producing >390 Mcfd (Figure 2b). However, the 10 000 bootstrap distributions (recreated from the empirical distribution) for the Barnett indicate overlap with the Denver-Julesburg (DJB), Pinedale, and Uinta CH₄ distributions, particularly at the high end of the distribution (Figure 2).

Relationship between Measured Site-Level Methane Emissions and NG Production. Recent studies report weak relationships between absolute CH₄ emissions and site-level characteristics, including NG production, oil production, water production, and/or site age.^{4,8,11,29} Given the limited information for individual sites, we can only examine the relationship between site-level CH₄ emissions and NG production.

Figure 3 shows the site-level absolute and production-normalized CH₄ emissions as functions of NG production. Figure 3b shows a strong trend of decreasing production-normalized CH₄ emissions with increases in site-level NG production. To quantify the trend, we fit the entire data set with quadratic robust weighted least-squares regression with bisquare weighting (see Materials and Methods):

$$\log_{10} \left[\% \text{CH}_4 \left(\frac{\text{kg/h}}{\text{kg/h}} \right) \right] = 0.072 \pm 0.056 (95\% \text{CI}) \times \log_{10} [\text{Prod}(\text{Mcfd})]^2 - 1.1 \pm 0.28 \times \log_{10} [\text{Prod}(\text{Mcfd})] + 1.96 \pm 0.34; r_{\text{adj}}^2 = 0.74.$$

On average, low NG producing sites emit a larger fraction of their CH₄ production than high NG producing sites and up to 74% of the variability is explained by variability in NG production rates (Figure 3). This implies that basins in which total NG production are dominated by high NG production sites are likely to have lower production-normalized CH₄ emissions and vice versa.

Figure 3 also shows modest increases in absolute CH₄ emissions with site-level NG production (quadratic robust weighted least-squares regression with bisquare weighting):

$$\log_{10} [\text{CH}_4(\text{kg/h})] = 0.071 \pm 0.056 (95\% \text{CI}) \times \log_{10} [\text{Prod}(\text{Mcfd})]^2 - 0.097 \pm 0.28 \times \log_{10} [\text{Prod}(\text{Mcfd})] - 0.23 \pm 0.33; r_{\text{adj}}^2 = 0.74$$

High NG production sites (e.g., > 1000 Mcfd/site) are generally newer facilities (SI Figure S3); they may have optimally performing equipment and components, and are likely subjected to more frequent on-site inspection and maintenance than old, low producing sites.⁸ Because of their high NG production rates, exceptionally high CH₄ emissions (e.g., > 10% of site-level CH₄ production) at these sites would likely be audible and/or visible, increasing the possibility for detection and repair if routine inspections are performed.

Both Figure 1 and Figure 3 highlight the significant scatter in CH₄ emissions within basins and within NG production bins; this underscores the stochastic character of emissions at any given site, which may result from sources that include malfunctions (e.g., separator dump valve stuck open), operational errors (e.g., storage tank venting from thief hatch accidentally left open), and/or process and design issues (e.g., overpressurized separators).^{27–29} Therefore, the fits in Figure 3 predict the emissions of an average site as a function of production but do not predict the emissions for any specific site. Fortunately, trends in average emissions are what is needed to develop national or basin-level emission estimates,

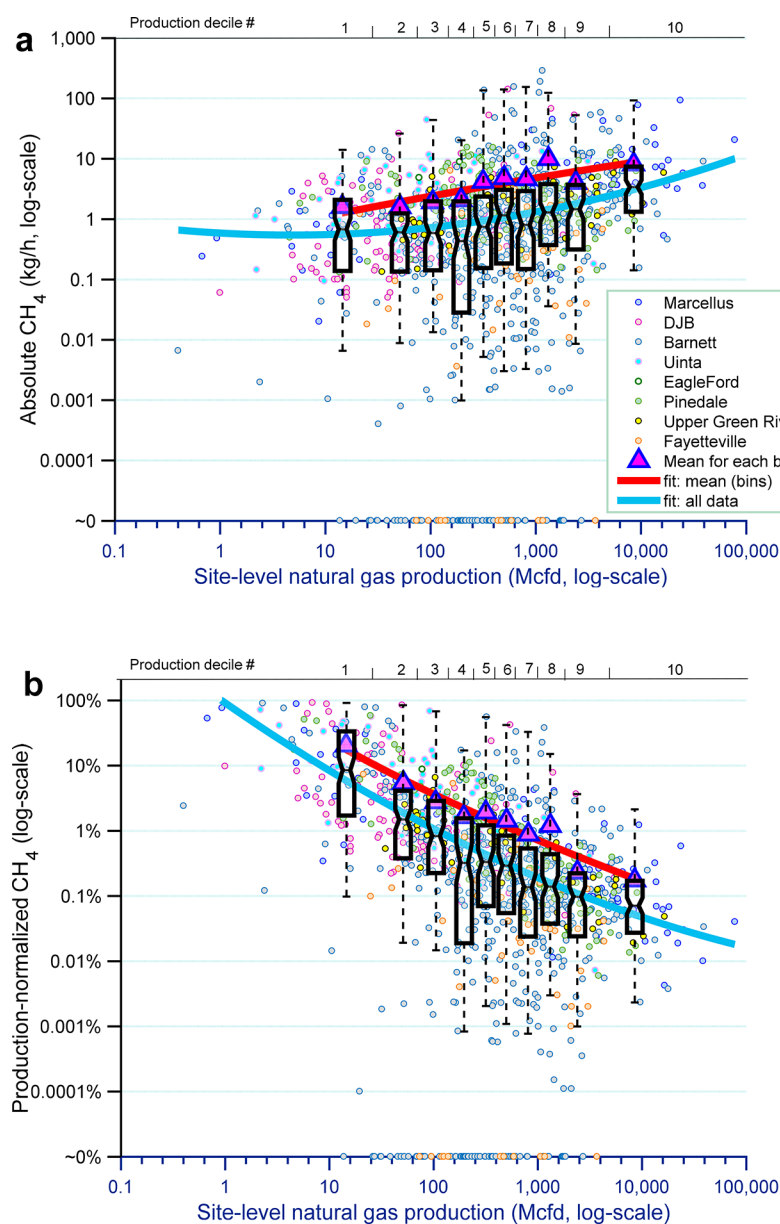


Figure 3. Relationship between site-level CH₄ emissions and NG production. (a) absolute and (b) production-normalized CH₄ emissions. Solid cyan lines show quadratic robust weighted least-squares regressions with bisquare weighting (see [Materials and Methods](#)) performed on the entire data set. Measured site-level CH₄ emissions were also binned by deciles of their site-level NG production, which are numbered sequentially on the top *x* axis. The notched box plots (outliers not shown) visually depict the data spread in each production decile. The black horizontal line in each notched box shows the median. The triangular purple symbols show the mean CH₄ emission rate in each production decile and the solid red lines show the polynomial fit through the mean CH₄ emission rate in each decile. These regression equations are (a) $\log_{10}[\text{CH}_4 \text{ (kg/h)}] = 0.30 \pm 0.14 \times \log_{10}[\text{Prod (Mcf/d)}] - 0.23 \pm 0.38$; $r^2_{\text{adj}} = 0.72$ and (b) $\log_{10}[\% \text{CH}_4 \text{ (kg/h/kg/h)}] = -0.71 \pm 0.15 \times \log_{10}[\text{Prod (Mcf/d)}] + 2.0 \pm 0.41$; $r^2_{\text{adj}} = 0.93$ for the absolute and production-normalized CH₄ emissions, respectively.

which integrate an average emission factor with activity data reflecting the total number of well sites.

Influence of High-Emitting Sites on Total Methane Emissions. Within each basin ([Figure 1](#)) and production bin ([Figure 3](#), notched box plots), the mean CH₄ emission rate is higher than the median because of the disproportionate influence of low frequency, high emitting sites. The high CH₄ emitters are commonly referred to as “super emitters”; since we lack information on the site-level CH₄ sources, we denote them simply as “high emitters” and identify them as the top 5% of sites based on the cumulative fraction of CH₄ emissions. [Figure 4a](#) shows, empirically, that the top 5% of high-emitting

sites account for 57% (CI: 40–70%) of cumulative CH₄ emissions, with each of these sites having site-level CH₄ emissions >13 kg/h/site. Furthermore, their cumulative CH₄ emissions are equivalent to 1.6% (CI: 1.1–2.2%) of their total CH₄ production. This result is consistent with the observation by Brandt et al.⁴⁴ that the largest 5% of leaks from NG systems typically contribute over 50% of total leakage volume. Overall, our results suggest that CH₄ emission models (or CH₄ emission factors) that do not adequately capture the disproportionate contribution of high emitters may significantly underestimate total emissions.

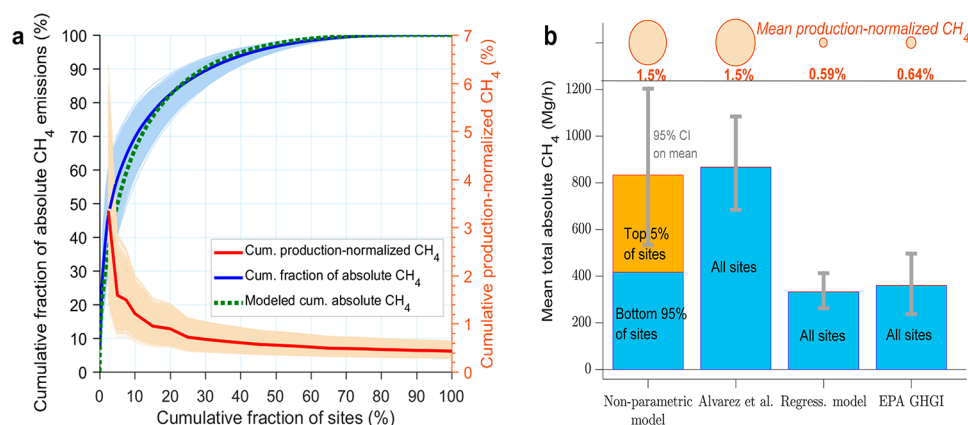


Figure 4. Total CH₄ emissions are dominated by a small fraction of high-emitting sites. (a) Site-level absolute CH₄ emissions distribution plotted in descending rank-order. Empirically ($n = 1009$), the top 5% of sites contribute 57% of total absolute CH₄ emissions (solid blue line); their cumulative CH₄ emissions are equivalent to 1.6% of their total CH₄ production (solid red line). The light blue and orange bands visually depict the 95% confidence intervals on the cumulative fraction of absolute and production-normalized CH₄ emissions, respectively. The dotted green line shows the predicted CH₄ distribution for all 498 000 U.S. onshore NG production sites as obtained from the nonparametric model—the top 5% of sites account for 50% of total CH₄ and have mean site-level CH₄ emissions of 17 kg/h/site (CI: 10–25). (b) Comparison of estimated total U.S. production CH₄ emissions based on (i) nonparametric model, (ii) total CH₄ emission estimate for all production sources reported by Alvarez et al.,⁴⁵ (iii) a regression model approach, and (iv) total onshore CH₄ emissions from the 2017 EPA GHGI (see Main Text). The top bubble plots visually depict the differences in production-normalized CH₄ emissions (see SI Section 2.2).

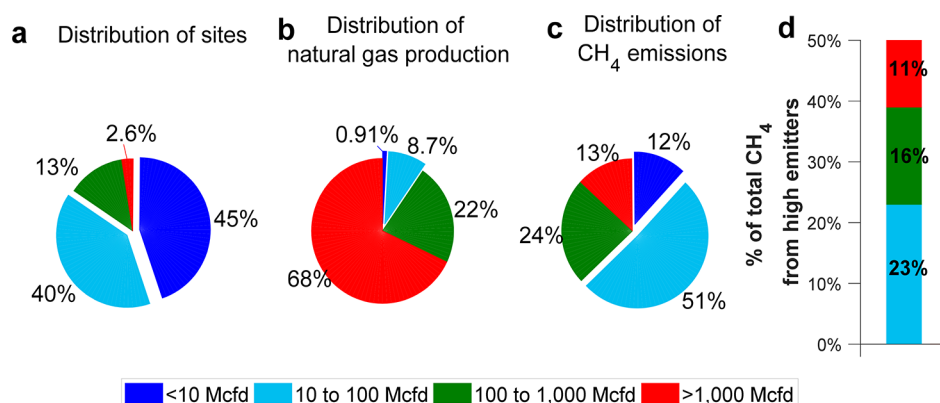


Figure 5. Distribution of sites, NG production, and CH₄ emissions based on four cohorts of site-level NG production. (a) Distribution of U.S. NG production sites in 2015 ($n = 498\,000$). (b) Distribution of their NG production (total = 83 Bcf). (c) Distribution of their estimated CH₄ emissions (total = 830 Mg/h). (d) CH₄ emissions from the high-emitting sites (none of the 220 000 sites producing <10 Mcfd was estimated to be a high emitter). High-emitting sites are defined as the top 5% of U.S. sites (based on the cumulative fraction of site-level CH₄ emissions ($n = 25\,000$)) and that emit >7.2 kg/h/site. Total CH₄ from high-emitting sites were estimated to be 420 Mg/h (95% CI: 260–630 Mg/h).

To quantify the importance of accurate accounting of high-emitters on national emission estimates such as the EPA GHGI,³³ we estimated, for the year 2015, the total U.S. CH₄ emissions from NG production using the two approaches previously described (see Materials and Methods). In the first approach, we use a robust regression model that captures the average site-level CH₄ emissions behavior and simulates a bottom-up inventory approach in which the full effect of extreme CH₄ emitters are not accounted for. Second, we use a nonparametric model that fully incorporates the disproportionate influence of high-emitting sites. For this analysis, we use the combined production-normalized CH₄ emissions data given the strong similarities in basin-specific distributions (Figure 2b) and robust trend with site-level NG production (Figure 3b). We include site-level production-normalized CH₄ data from all basins, including those where small sample sizes precluded a comparative assessment of their CH₄ distribution. We acknowledge that this and other potential sampling

artifacts discussed above likely increase the overall uncertainty in total estimated CH₄ emissions.

When combined with activity data from Drillinginfo's DI Desktop,⁴¹ the regression model approach estimates total CH₄ emissions of 330 Mg/h (95% CI on mean: 260–410; or 0.67 kg/h/site and equivalent to production-normalized emissions of 0.59%; Figure 4b) in 2015. In contrast, the nonparametric model yields an estimate that is more than two times the regression model results, that is, total CH₄ emissions of 830 Mg/h (CI: 530–1200; or 1.7 kg/h/site and equivalent to production-normalized emissions of 1.5%).

The regression model approach is similar, in principle, to the bottom-up inventory methods in which an average CH₄ emission factor is applied to activity data, which may include count of wells, components, and/or equipment at a site or region. This is the approach typically used in government inventories such as the EPA GHGI.³³ Our estimated total CH₄ emissions based on the regression model (330 Mg/h) is similar to the 360 Mg/h of total CH₄ emissions for onshore oil and

Methane emissions from natural gas production sites in the United States (2015)

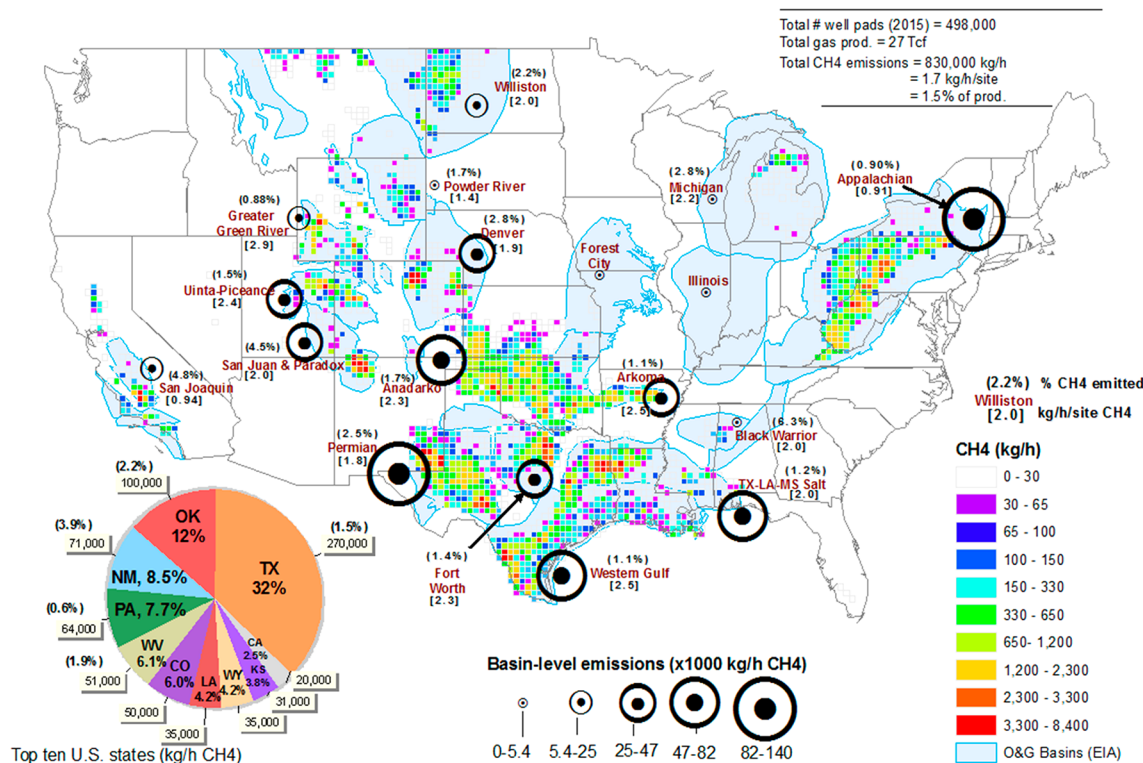


Figure 6. Spatial distribution of CH₄ emissions, plotted on 35km × 35km grid cells. Percentages and numbers in parentheses above and below basin names indicate the basin-level production-normalized and average site-level CH₄ emission rates, respectively. Pie chart labels indicate the predicted mean total CH₄ emissions (kg/h); percentages above the labels indicate the production-normalized CH₄ emissions for the top five states, while percentages inside each pie indicate the predicted fraction of total U.S. CH₄ contributed by that state. Additional data can be found in SI Tables S7, S9, and S11 and in the provided Google Earth kmz file. The oil and gas basin boundaries are from the U.S. EIA.⁴⁶ Map data source: ArcUSA, U.S. Census, and ESRI. The map was created using ArcGIS software by ESRI (www.esri.com) and used herein under license.

NG production sites as reported in the 2017 EPA GHGI for 2015 emissions (Figure 4b). Furthermore, the EPA GHGI estimate is similar to our mean estimate of 420 Mg/h (CI: 300–570; or 0.88 kg/h/site (CI: 0.61–1.2)) for the lowest-emitting 95% of all U.S. sites (based on cumulative fraction of emissions) as obtained from the nonparametric model (Figure 4b). The robust regression fit (cyan line in Figure 3b) essentially passes through the median CH₄ emission rate in each production bin as the effect of extreme CH₄ outliers are downweighed in favor of tracing the underlying trend through the bulk of the data. Thus, total emissions estimates based on the robust regression model and the results for the lowest-emitting 95% of sites do not fully account for the CH₄ emissions from the exceptionally high emitters.

Our nonparametric model incorporates high emitters (i.e., the top 5% of sites). Its estimate of the total CH₄ emissions is 2.3 times higher than the EPA GHGI's estimate for total CH₄ from the oil and NG production sites (Figure 4b). Similar discrepancies between bottom-up inventories and measurements have been reported in recent studies.^{17,18,25,26,30,45} Herein, our results suggest that CH₄ emissions from the high emitters (national mean: 17 kg/h/site (CI: 10–25); range: 7.2–1100), which account for 50% (CI: 32–75%) of cumulative emissions (Figure 4a), are primarily responsible for the discrepancy between our predicted total CH₄ and the EPA GHGI estimate. That is, the nonparametric model results match the EPA GHGI only when we exclude the contribution of the top 5% of high emitting sites. As reported in the 2017

GHGI,³³ the 2015 national CH₄ emissions for the NG gathering and processing (2.8 Tg), transmission and storage (1.3 Tg), and distribution (0.44 Tg) sectors already incorporate data from skewed emissions distributions obtained in recent sector-specific measurement-based campaigns.^{14,17,18} Our analysis supports a similar adjustment of CH₄ emissions for the NG production sector.

Distribution of Methane Emissions among Natural Gas Production Sites. Figure 5 summarizes the total CH₄ predictions stratified by production level. We define low, intermediate, and high NG production sites as sites producing <100 Mcfd, 100 to 1000 Mcfd, and >1000 Mcfd, respectively. Low NG production sites account for 85% of the total number of sites but only 9.6% of total NG production (Figure 5a,b). Although their mean site-level CH₄ emissions are low (0.46 and 2.1 kg/h/site for the <10 Mcfd and 10 to 100 Mcfd sites, respectively; SI Table S10), their very large number makes them an important source of CH₄ emissions nationally, contributing nearly two-thirds (63% (CI: 45–83%)) of the total CH₄ emissions. In contrast, high NG production sites (>1000 Mcfd/site) contribute two-thirds of total U.S. NG production and have higher mean site-level CH₄ emissions (8.3 kg/h/site; SI Table S10). However, they are few in number (i.e., they account for only 2.6% of the total number of sites) and contribute only 13% (CI: 7–21%) of the total CH₄ emissions.

We estimate that none of the 220 000 sites (45% of all sites) producing <10 Mcfd/site are high emitters; these low-

production sites had mean site-level CH₄ emission estimate of 0.46 kg/h/site (CI: 0.35–0.58; [SI Table S10](#)). In contrast, we estimate that 47% of the total CH₄ from high-emitting sites came from 8.3% of sites producing 10–100 Mcfd/site. High emitters in this cohort accounted for 23% of the total CH₄ from all sites ([Figure 5d](#), [SI Table S10](#)). The remainder of the emissions from high emitters are contributed by sites with intermediate (16% of total CH₄ from all sites) and high NG production (11% of total CH₄ from all sites, [Figure 5d](#)).

Spatial Distribution of Methane Emissions. [Figure 6](#) shows the estimated spatial distribution of site-level CH₄ emissions calculated from the nonparametric model, as previously discussed (i.e., the site-level CH₄ emissions distributions for all 498 000 NG production sites plotted in [Figure 6](#) is the same distribution shown in [Figure 4a](#) (dotted green line)). Using site-specific location data from Drillinginfo,⁴¹ the estimated emissions were then geo-spatially joined to 35 km × 35 km grid cells and summed to give the grid-specific total CH₄ ([Figure 6](#)).

We predict production CH₄ hotspots in the liquids-rich fairway of the Appalachian Basin (southwestern Pennsylvania and northern West Virginia), and in northwestern (San Juan Basin) and southeastern (Permian Basin) New Mexico, and in Weld County, Colorado (Denver Basin; [Figure 6](#)). Methane hotspots are not necessarily areas with high NG production. For example, Weld County (CO) was the eighth largest NG producing county in 2015 but is predicted to be the highest CH₄ emitting county in 2015 (26 Mg/h (CI: 16–34 Mg/h)). The emissions in Weld County are four times greater than that from Susquehanna (PA), the highest NG producing county. This is due to the very large number of sites with relatively low NG production in Weld County (13 000 sites) compared to Susquehanna (400 high producing sites).

Our analysis predicts wide variability in CH₄ emissions among states and among basins. For example, we predict that Texas contributes approximately one-third (32% (95% CI: 20–48%); [Figure 6](#), [SI Table S11](#)) of total CH₄ emissions from NG production sites, roughly equivalent to the contribution of the combined CH₄ emissions from NG production sites in Oklahoma, New Mexico, and Pennsylvania (28% (95% CI: 19–39%)). Additionally, predicted basin-specific mean absolute CH₄ emissions per site ranged from 0.91 kg/h/site (CI: 0.62–1.2) in the Appalachian to 2.9 kg/h/site (CI: 1.6–3.9) in the Greater Green River Basin ([SI Table S9](#)). Mean production-normalized CH₄ emissions ranged from 0.88% (CI: 0.48–1.2%) in the Greater Green River Basin to 4.5% (CI: 3.3–6.6%) in the San Juan Basin ([Figure 6](#); [Table S9](#)). These trends are caused by differences in the distributions of both the number of sites and their NG production characteristics. For example, the Appalachian Basin has the highest basin-level CH₄ emissions (140 Mg/h (CI: 95–180 Mg/h) or 17% of total CH₄ emissions ([Figure 6](#)). However, the Appalachian and Greater Green River Basins have the lowest estimated production-normalized CH₄ emissions of approximately 0.90% ([Figure 6](#)). NG production in both of these basins are dominated by high-producing sites with relatively low estimated production-normalized emission rates. These sites account for 94% and 72% of total NG production in the Appalachian and Greater Green River Basins, respectively. Similarly, the high estimated production-normalized CH₄ emissions of 4.5% (CI: 2.9–6.0%) in the San Juan Basin ([Figure 6](#); [SI Table S9](#)) reflects the large contribution to total

NG production (90%) from sites producing <1000 Mcfd/site in this basin.

Comparison with Previous Literature Estimates. Two previously published studies used site-level CH₄ emissions data that are part of the consolidated data set in the present study to estimate basin-level²⁶ or state-level CH₄ emissions.⁸ Zavala-Araiza et al.²⁶ reported 2013 site-level CH₄ emissions of 1.8 (CI: 1.3–2.5) kg/h/site for the Barnett; the 2015 site-level CH₄ emissions estimates in the present study of 2.4 (CI: 1.4–3.6) kg/h/site for the Fort Worth Basin are in good agreement with their study. Similarly, our estimate of 115 Mg/h (CI: 78–150) for 2015 CH₄ emissions for NG producing sites in Pennsylvania and West Virginia overlaps with a previous estimate by Omara et al.⁸ for these sources in 2014 (144 Mg/h (CI: 70–190)). Finally, our national estimate for total CH₄ emissions from NG production sites (830 Mg/h (CI: 530–1200)) compares well with recent estimates by Alvarez et al.⁴⁵ (870 Mg/h (CI: 680–1080, [Figure 5b](#)) that were based on site-level measurements but utilized a different extrapolation approach incorporating parametrized nonlinear models.²⁶

Recent aircraft studies estimated the total CH₄ emissions from different NG production regions.^{19–24,31,32} These studies report widely varying mean production-normalized CH₄ estimates, ranging from approximately 0.3–9% in northeastern PA (Marcellus) and Uinta Basin, respectively. Our analysis predicts that the distribution of sites and their NG production levels are important contributors to these trends. For example, basins in which low producing sites dominate site count and NG production (e.g., San Juan) have much higher production-normalized CH₄ emissions than basins where NG production are dominated by high NG producing sites (e.g., Greater Green River). We compared our new bottom-up estimates with these top-down studies ([SI Section 3.6](#); [Figure S20](#)), which estimate CH₄ emissions from all oil and NG sources. Our predictions explain, on average, 58% of the airborne top-down CH₄ emissions (20–129% of basin-specific airborne CH₄ emissions ([SI Table S12](#))). There are uncertainties in both estimates. For aircraft measurements, CH₄ source attribution and mass balance closure are uncertain, while the uncertainties in our bottom-up estimates were dominated by variability in study-specific mean site-level emissions.

Other factors (beyond number of sites and site production characteristics) such as new state/local regulations^{34–38} or voluntary emissions reductions programs performed by specific operators, likely also contribute to basin-to-basin variability, but we could not assess those factors in this analysis. Additionally, our approach assumes that the large and diverse ensemble of sites considered here reproduces the distribution of emissions across the NG production system at any given point in time. However, there are uncertainties on CH₄ emissions distributions that are difficult to quantify based on available data. Future studies are needed to specifically address these factors.

■ ASSOCIATED CONTENT

§ Supporting Information

The Supporting Information is available free of charge on the ACS Publications website at DOI: 10.1021/acs.est.8b03535.

A Google Earth kmz file showing the data presented in [Figure 6](#), and documentation that describes the measurement results obtained in the present study, characteristics and distribution of natural gas production

sites, and additional study results, figures, and tables (PDF, ZIP)

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Author Contributions

A.L.R., R.S., and A.A.P. designed the research. M.O., N.Z., M.R.S., X.L., A.E., R.C., and R.S. performed the field measurements. M.O. and N.Z. analyzed data. M.O. prepared the manuscript with feedback from all authors.

Notes

The authors declare no competing financial interest.

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Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings

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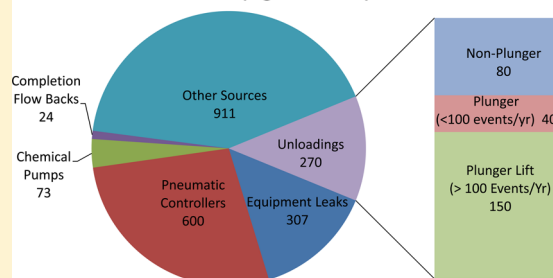
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Supporting Information

ABSTRACT: Methane emissions from liquid unloadings were measured at 107 wells in natural gas production regions throughout the United States. Liquid unloadings clear wells of accumulated liquids to increase production, employing a variety of liquid lifting mechanisms. In this work, wells with and without plunger lifts were sampled. Most wells without plunger lifts unload less than 10 times per year with emissions averaging 21 000–35 000 scf methane (0.4–0.7 Mg) per event (95% confidence limits of 10 000–50 000 scf/event). For wells with plunger lifts, emissions averaged 1000–10 000 scf methane (0.02–0.2 Mg) per event (95% confidence limits of 500–12 000 scf/event). Some wells with plunger lifts are automatically triggered and unload thousands of times per year and these wells account for the majority of the emissions from all wells with liquid unloadings. If the data collected in this work are assumed to be representative of national populations, the data suggest that the central estimate of emissions from unloadings (270 Gg/yr, 95% confidence range of 190–400 Gg) are within a few percent of the emissions estimated in the EPA 2012 Greenhouse Gas National Emission Inventory (released in 2014), with emissions dominated by wells with high frequencies of unloadings.

Estimated Annual Emissions from Upstream Natural Gas Production Sector in the United States (Gg Methane)



INTRODUCTION

Natural gas production in the United States is increasing, driven by increased use of horizontal drilling and hydraulic fracturing.¹ As natural gas production has increased, interest has increased in the emissions of greenhouse gases along the natural gas supply chain.^{2–10} Methane, the primary component of natural gas, is a potent greenhouse gas, and a variety of sources contribute to methane emissions along the natural gas supply chain. For some of these sources, emission measurements are sparse, including measurements of emissions from pneumatic controllers and liquid unloadings.¹¹ Measurements of emissions from pneumatic controllers have been described in a companion manuscript.¹² This work reports on emissions from gas well liquid unloadings.

A liquid unloading may be necessary when a gas well that also produces oil or water accumulates liquids in the well bore. The liquids accumulation may be due to a variety of causes, including decreases in gas velocity in the well, decreases in reservoir pressure, or changing gas to liquid ratios. As liquids accumulate, well production can decline and an operator may choose to unload the liquids from the well to restore production. Liquids can be unloaded in a variety of ways. For example, the well tubing can be modified to increase gas velocity or a pump may be installed to remove downhole

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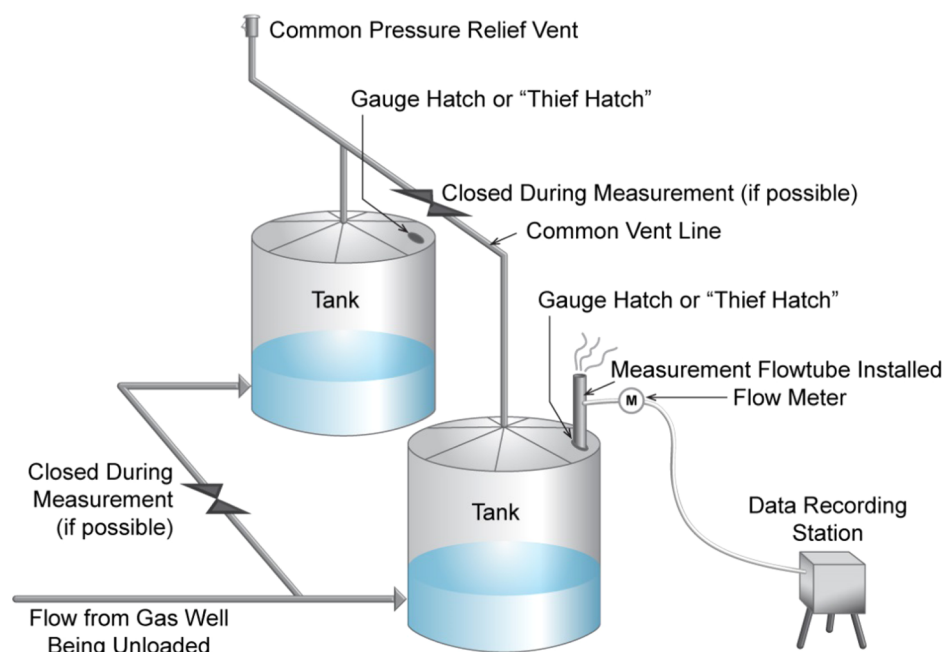


Figure 1. Conceptual diagram of a tank layout on a well site and the positioning of the temporary stack used to measure volume of gas vented during a liquid unloading.

liquids. Neither of these methods lead to venting emissions. Other unloading methods, such as temporarily diverting the flow from the well to an atmospheric vent, do lead to emissions. This work focuses on unloadings that result in emissions.

In the most recent national inventory of greenhouse gas emissions (for calendar year 2012, released in 2014, referred to here as the EPA 2012 GHG NEI),¹³ the EPA estimates that 60 810 natural gas wells, out of an estimated 470 913 natural gas wells in the United States (not including oil wells with associated gas production), have liquid unloadings that result in methane emissions. This represents 13% of gas wells in the EPA 2012 GHG NEI. Collectively, liquid unloadings from these wells are estimated to emit 273.6 Gg of methane per year (14.2 billion standard cubic feet, bcf), or approximately 14% of the estimated 1992 Gg of methane emissions from the natural gas production portion of the natural gas supply chain.

The estimates of methane emissions from liquid unloadings in EPA 2012 GHG NEI are generally consistent with more recent information collected through the EPA's Greenhouse Gas Reporting Program (for calendar year 2012, released in 2013, referred to here as the EPA 2012 GHGRP).¹⁴ The GHGRP reports approximately 276 Gg of methane emissions from liquid unloadings at facilities that meet threshold reporting requirements. Information for 58 663 wells that have unloading emissions was reported in 2012. In October 2014, GHGRP data were released for reporting year 2013 as well as revised data for reporting year 2012. In the 2014 data release, the number of wells with methane emissions from unloadings was reported as 55 491 for 2013, a 5.4% decrease from the number of wells originally reported for 2012. The number of wells with methane emissions from unloadings in 2012 was revised from 58 663 (released in October 2013) to 59 162 (released in October 2014). In this work, the 2012 data are used in order to allow comparisons with the 2012 GHG NEI. The originally released data are used since changes in reporting for 2012, as reflected in the well count, were relatively minor. Some changes were more significant, however, so a

sensitivity analysis, using revised 2012 and 2013 GHGRP data, is reported in Supporting Information (SI). The liquid unloading emission estimates from the EPA GHGRP are shown, by production region, in SI (Section S1).

Emissions from liquid unloadings of natural gas wells are not uniformly distributed in time or space. Estimated emissions from liquid unloadings are spatially concentrated in Rocky Mountain production regions. Wells in the Rocky Mountain region account for more than half of estimated emissions from liquid unloadings in the 2012 GHGRP. Temporal distributions also vary. Some wells release unloading emissions several times per day while others may release unloading emissions only once per year or once during the well's production life cycle. Wells may only release unloading emissions for a portion of their production lifetime, leading to a dependence of unloading emissions on well age. In addition to spatial and temporal variability in emissions of wells that vent, both estimates and measurements indicate that a small fraction of wells that vent account for a majority of emissions. For example, for one type of well with unloading emissions (wells without plunger lifts, see definition later in text), emission estimates reported by the American Petroleum Institute/America's Natural Gas Alliance (API/ANGA), indicate that three percent of wells accounted for half of emissions from this type of well and half of the wells accounted for more than 90% of emissions.¹⁵ In a limited number of measurements of methane emissions from a single type of well with unloading emissions (wells without plunger lifts—see definition later in text), Allen et al.¹¹ found that 95% of the emissions came from less than half of the wells.

Emission estimates, and a limited number of measurements of methane emissions from liquid unloadings, both suggest that a small fraction of wells, in particular geographical regions, and at particular times in the well's life cycle, account for a large fraction of liquid unloading emissions. These characterizations of unloadings emissions are primarily based on emission estimates, however, and there are few data in the scientific literature to test the reliability of emission estimates. This leads

to potentially large uncertainties in the emissions from this source category. More measurement data are needed, along with a better understanding of the relationships between well characteristics and unloading emissions.

This work reports measurements of methane emissions from 107 natural gas wells with emissions associated with liquid unloading. These data represent the most extensive set of measurements of emissions from liquid unloadings in the scientific literature. The relationships between emissions magnitude, unloading event frequency and other well characteristics are explored.

MATERIALS AND METHODS

Emission Measurements. The liquid unloadings reported in this work are grouped as plunger-lift unloadings and unloadings of wells without plunger lifts.

In a manually triggered unloading of a well without a plunger lift, an operator manually diverts the well's flow from a production separator, which typically operates at pressures of multiple atmospheres, to an atmospheric pressure tank. This allows the well to temporarily flow to a lower pressure destination (the atmospheric pressure tank or vent, rather than the pressurized separator). The resulting higher pressure gradient allows more gas to flow, increasing velocity in the production tubing and entraining and lifting liquids out of the well. Gas is discharged through the tank vent to the atmosphere until liquids are cleared. In a small number of wells (~0.1% of wells reported by companies participating in this work), this process is automated, resulting in two subcategories of unloadings for wells without plunger lifts, manual and automatic. All of the measurements reported in this work for wells without plunger lifts are for wells that had unloadings that were manually triggered; no wells without plunger lifts were observed in the sampling that had automated unloadings.

Emissions from unloadings of wells without plunger lifts were measured in this work by directing flow through a temporary stack installed on top of the vent. Figure 1 shows a conceptual diagram of a tank layout on a well site and the positioning of the temporary stack. Grounded metal or metal lined tubing was used to construct the temporary stack, to prevent static discharge. Flow rate through the temporary stack was measured continuously, near the centerline of the temporary stack, using a thermal gas mass flow meter. The thermal meter was extended into the middle of the temporary stack, which was between two and eight inches in diameter, with the diameter depending on the anticipated flow rate. Since the width of the meter's probe was approximately 3.5 cm (1.4 in.), the thermal meter recorded a centerline velocity. Total volumetric flow was calculated by multiplying the product of the measured gas velocity and the cross-sectional area of each stack by a correction factor to convert the centerline velocity in the stack to an estimated average velocity in the stack, accounting for the change in velocity profile from friction near the stack walls and accounting for the cross sectional area of the stack obstructed by the flow meter (see SI Section S2). In some well configurations (31 of the 107 wells on which measurements were made), measurement through a temporary stack on the atmospheric tank was not technically feasible. In these cases, measurements were made by inserting a segment of pipe (with the thermal gas mass flow meter in the pipe) into the process line between the separator and the atmospheric tank in order to measure the flow into the tank.

The methane fraction of the vented gas was assumed to be equal to the methane fraction in the normally produced gas. This was presumed to be a more accurate indicator of total methane emissions than measurements of the gas composition made through the temporary stack. The gas exiting through the temporary stack during the unloading period is a combination of the unloaded gas from the well and the gas initially in the vapor space of the tank (typically much lower in methane than the site's produced gas). At the end of the unloading, the tank will contain more methane, from the unloading, than was in the tank at the start of the unloading. This methane, which is associated with the unloading event, will eventually be released as part of normal tank operations. Multiplying the measured vented gas volume by the methane fraction of the produced gas captures these emissions that occur because of the unloading but that are not released during the period when the tank is actively venting.

Uncertainty in these measurement methods is estimated at 10–20% of the measured emissions and this estimate is dominated by the assumed uncertainty in the flow, which includes both uncertainties in the stack gas volumetric flow measurement, and determining when flows return to zero. Variability in the gas composition from the well is expected to be much less than 10%. As described in the Results section, these measurement uncertainties are small compared to the combined measurement uncertainty and uncertainty introduced by selecting only a subpopulation of wells for measurement (sampling uncertainty), which are 50% or more of measured emissions.

Liquids can also be unloaded from a well using a plunger lift system. This liquid removal operation holds a plunger at the top of the well, and either manually or by automation occasionally closes (shuts-in) the well and releases the plunger, allowing it to fall down the well bore below the accumulated liquids. The well is then reopened, allowing the gas to push the plunger and the liquid back up the well bore as a slug of liquid. If the plunger returns to the top and the liquid and gas flow to the separator, there is no venting and all gas from the separator is routed to sales. In some cases, if the plunger does not return to the surface as expected, the plunger controller may bypass the separator and direct the flow to an atmospheric pressure vent, such as a vented tank. Directing flow to the lower pressure vent causes the plunger to return to the surface but also allows gas to vent. Plunger cycles may be initiated manually, on a timed interval, or based on certain well parameters such as a reduced gas flow. In this work, measurements were made on both wells in which the unloading was automated through use of a controller (automatically triggered), and wells in which the plunger lift cycle was manually initiated by an operator (manually triggered).

In both the manually triggered plunger lift unloadings and the automatically triggered plunger lift unloadings, the volume of vented gas was measured using the same procedures as used for the wells without plunger lifts. For the automatically triggered unloadings, the measurement equipment was typically left in place for one to several days, making measurements continuously. This allowed automated plunger unloading venting events to be measured only when and if they occurred in routine operation, without artificially triggering the events. For all the plunger lift unloading events, the composition of the vented gas was assumed to be the same as the composition of the gas produced by that well. Produced gas composition was provided by site operators.

Table 1. Unloading events measured in this work. Wells with manual unloadings typically had one event per well, while automated Plunger Lift Unloadings Had Multiple Events Per Well; A Mapping of Region Boundaries is Provided in Supporting Information

type of well	initiation system	wells with unloadings sampled				
		U.S. total	Appalachian	Rocky Mountain	Gulf Coast	Mid-Continent
plunger	auto	25	0	20	1	4
	manual	50	7	29	1	13
non- plunger	manual	32	4	2	14	12
total		107	11	51	16	29

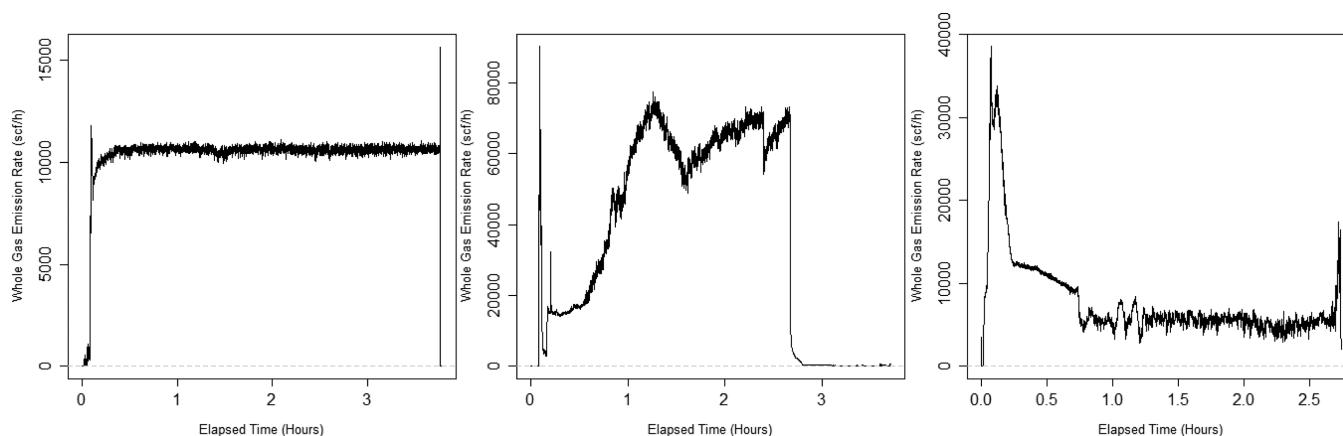


Figure 2. Representative time series of methane flow rates during manually triggered liquid unloadings from wells without plunger lifts (USH-47-0201 left; USH-47-0701 middle; UCG-03-0301 right); Note differences in horizontal and vertical scales.

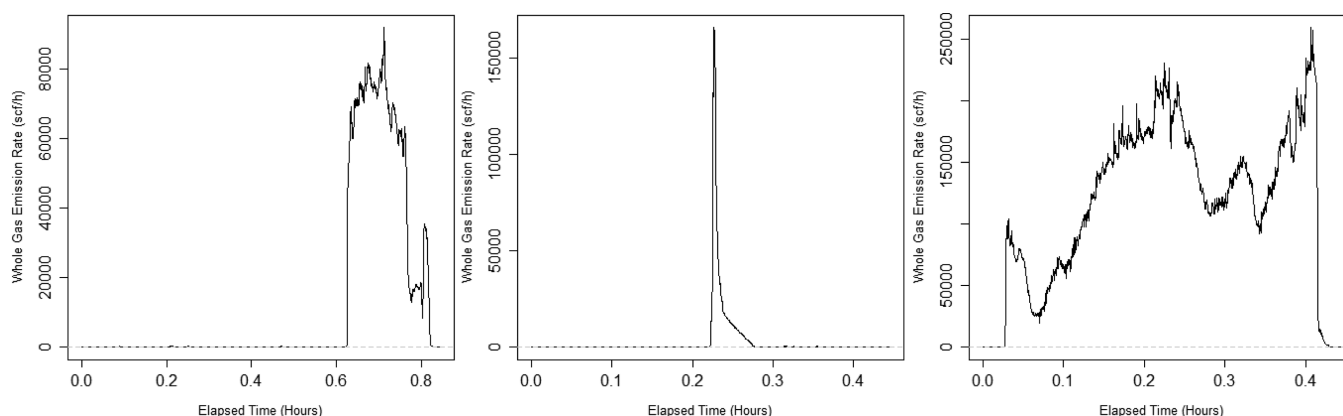


Figure 3. Representative time series of methane flow rates during manually triggered liquid unloadings from wells with plunger lifts (UBB-45-0101 left; UJR-46-0601 middle; USH-45-0202 right); Note differences in horizontal and vertical scales.

Sampling Strategies. Emission estimates reported through the EPA 2012 GHGRP¹⁴ indicate that a small fraction of wells, in particular geographical regions, account for a large fraction of emissions from liquid unloadings. The sampling strategy employed in this work was to sample most extensively in regions that were likely to dominate emissions (SI, Section S1). Details of the sampling approach are provided in SI. Briefly, the sampling team would visit a region for one or multiple weeks and sample a randomly selected subset of those wells that were unloading during that period. Consequently, more samples were collected on wells that unloaded more frequently. The features of these sample collection methods (preferential sampling in regions with high estimated emissions from unloadings and sampling of wells that tended to have high unloading frequencies) are important to consider when the data

presented in this work are used to establish national emission estimates.

RESULTS AND DISCUSSION

Methane emissions from liquid unloadings were measured at 107 natural gas wells. A summary of the geographical locations of the wells sampled is provided in Table 1.

For the 32 wells without plunger lifts (manually unloaded) sampled in this work, one event was typically sampled for each well; a few wells had more than one event sampled and for these wells, average values are reported. The unloadings of wells without plunger lifts sampled in this work had durations that lasted between 0.17 and 4.5 h, and vented methane volumes that ranged between 550 and 135 000 standard cubic feet (scf) of methane per event (0.011–2.6 Mg). Representative time series for the methane emissions from wells without

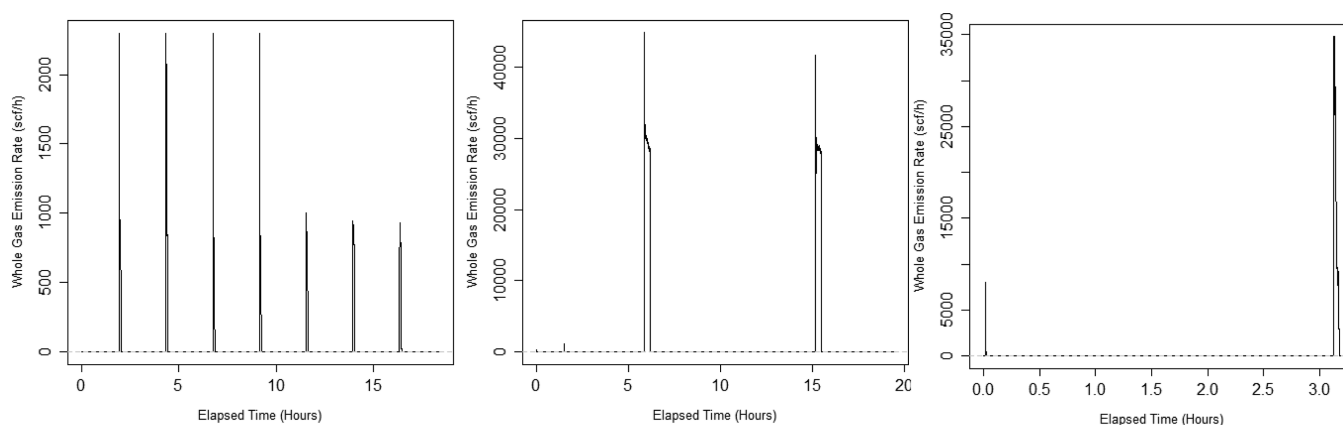


Figure 4. Representative time series of methane flow rates during automatically triggered liquid unloadings from wells with plunger lifts (UBB-42-0401 left; UBB-42-0201 middle; UEF-49-0501 right); Note differences in horizontal and vertical scales.

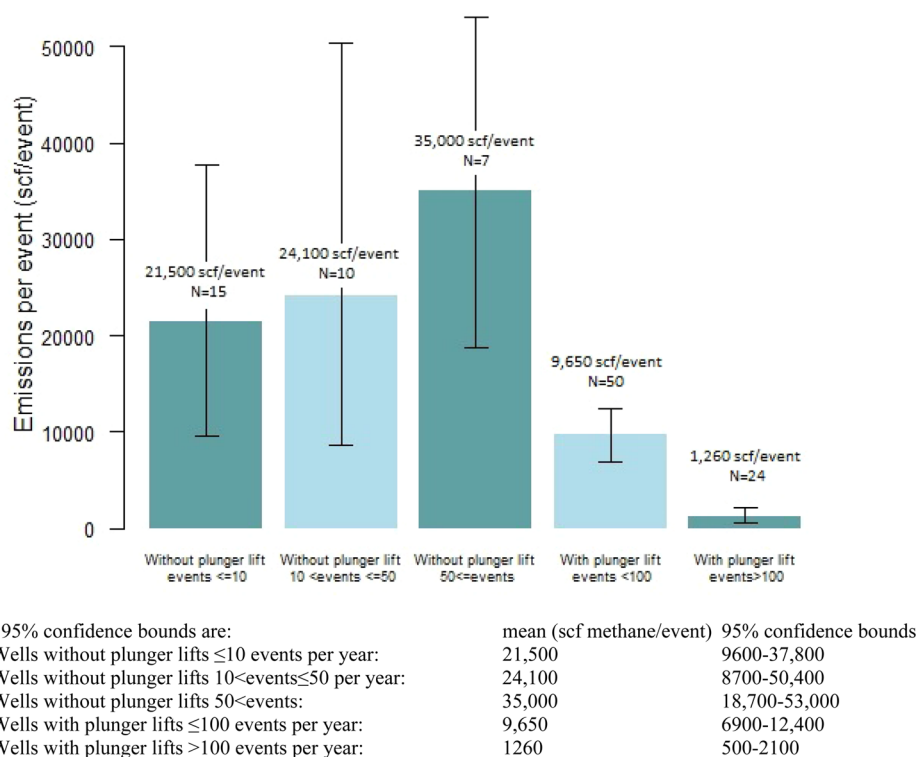


Figure 5. Average emissions per event for wells with and without plunger lifts, sorted by frequency of events (events per year per well).

plunger lifts are shown in Figure 2. These three events shown had durations that ranged from 2.72 to 3.75 h. Vented volumes for these three events shown ranged between 21 000 and 135 000 scf methane (0.40–2.6 Mg). As illustrated by these representative time series, some manual unloadings without plunger lift rapidly rose to a high flow rate, then maintained a steady flow throughout the event; others rose more slowly to a peak flow, then had variable flow during the event; still others rapidly rose to a peak flow, then had declining flows throughout the event. This complex flow behavior makes it difficult to generalize about the flow characteristics for manually triggered unloadings of wells without plunger lifts.

For the 50 plunger lift wells with manually triggered unloadings, one event was typically sampled for each well. The manual unloadings of wells with plunger lifts sampled in this work had durations that lasted between 0.03 h and more than 3 h, and had vented methane volumes that ranged

between approximately 200 and 49 000 scf methane per event (0.004–0.94 Mg). Representative time series for the methane emissions from a manual unloading are shown in Figure 3. These three events shown had durations that ranged from 1.2 to 20 min. Vented volumes ranged between 1220 and 27 000 scf methane for the three events shown (0.02–0.52 Mg). As illustrated by these representative time series, some manually triggered unloadings with plunger lift rapidly rose to a high flow rate, then almost immediately fell rapidly, leading to a relatively short duration event; others rose rapidly to a peak flow that was maintained for 5–10 min or more; still others had complex flow patterns over an event lasting 10 min or more. As was the case for manually triggered unloadings without plunger lifts, this complex flow behavior makes it difficult to generalize about the flow characteristics.

For automated plunger lift wells, the sampling equipment was left in place for one to several days at each well, and

typically more than one event was sampled for each well. The automatically triggered unloadings (with plunger lift) sampled in this work had durations that lasted between <1 min and more than 20 min, and vented methane volumes that ranged from 50 scf methane to more than 8000 scf methane per event) (0.001–0.15 Mg). The numbers of events sampled per well ranged from 2 to more than 70; average values of emissions per event were used when multiple events were recorded. Representative time series for the methane emissions from automated plunger lift unloadings are shown in Figure 4. Individual unloading events for these three wells had durations that ranged from 2 to 20 min. Vented volumes per event ranged between 60 and 8600 scf methane for the three wells shown (0.001–0.15 Mg). As illustrated by these representative time series, some plunger lift wells with automated unloadings had emissions per event that were quite similar, and that occurred with a regular frequency. In contrast, however, some automated plunger lift wells had events that had qualitatively different emissions and/or variable event frequencies.

SI (Section S3) provides details of the unloading emissions and well characteristics for each of the 107 wells sampled in this work. A summary is provided in Figure 5. A relatively small number of wells have high emissions and most wells have much lower emissions. For example, 20% (6 of 32) of the wells account for 83% of the annual emissions for wells without plunger lifts, where annual emissions are estimated by multiplying the emission for an unloading event, measured in this work, by the number of times that well unloaded during calendar year 2012 or 2013 (whichever was the most recent report available), as reported by the well operator. The six wells that account for 83% of the annual emissions of wells without plunger lifts vent 6% of their collective annual production. For manually and automatically triggered plunger lift wells, 20% of the wells account for 65% and 72% of the annual emissions, respectively. These wells vent 2% and 20% of their collective annual production, for manually and automatically triggered wells, respectively.

Because the distributions of event emissions are not normally distributed about a mean, uncertainties in the average values of emissions per event are reported based on the results of a bootstrapping method, rather than as a simple standard deviation of the data set. In the bootstrapping procedure, the original data set of each type of well was recreated by making random event selections, with replacement, from the data set. A total of 1000 of these resampled data sets were created and the mean value of the emissions for each resampled data set was determined. The 95% confidence intervals for the emission estimates represent the 2.5% and 97.5% percentiles of the means in the 1000 resampled data sets. So, for example, for the 25 automatically triggered plunger lift wells, a mean value for emissions per event, for each well, was calculated by selecting 25 emission measurements, at random and with replacement. This mean was tabulated and the process was repeated 1000 times to generate 1000 mean values. The 2.5% and 97.5% percentiles were determined to be 538 and 2085 scf methane per event, and these values are the 95% confidence bounds for the mean value of the measurements (in this case 1260 scf methane/event). The bootstrapping procedure leads to a combined sampling and measurement uncertainty. This uncertainty has a much larger range (typically 50% or more of the mean value, see Figure 5) than would be estimated from the uncertainty associated with the measurement alone (approximately 10–20% of the measured value) and is a

reflection of the heterogeneity of well characteristics in the data sets and the underlying population of wells with unloading emissions.

Statistical analyses were conducted to identify well and unloading event characteristics that could explain the variability in the measured emission data. Variables that were considered included well pressures, well bore volumes, well ages, unloading event durations and unloading frequencies. The variable that explained the largest amount of variability in the observed annual well emissions was unloading frequency, although there was also a positive correlation of event frequencies with well age (older wells had more unloading events per year than younger wells) and a negative correlation of annual emissions with well depth (deeper wells, which were generally newer, had lower annual emissions than shallower, generally older, wells). Correlations with emissions per event were generally weaker than for annual emissions. Additional details are provided in SI (Section S4). As shown in Figure 5, for wells without plunger lifts, average emissions for individual unloading events range between 21 000 and 35 000 scf methane per event, if the events are binned into wells that have less than 10 events per year, between 11 and 50 events per year, and 51 or more events per year. The differences in annual emissions from manually unloaded wells without plunger lifts are largely due to the frequency of events, rather than the volume of gas emitted per event. For wells with plunger lifts, Figure 5 reports average emissions in two frequency bins. Manually triggered plunger lift wells were binned as a single group; all had less than 100 events per year (maximum observed value of 52 events per year). Automatically triggered plunger lift wells were also considered as a single category since all of these wells had more than 180 unloadings per year (average of 1870 unloadings per year in the sampled population). Plunger lift wells that were manually triggered had average emissions per event of 9650 scf methane. Plunger lift wells with automated triggering of the unloading had average emissions of 1260 scf methane per event.

The measured emissions per event were compared to predictions made using emission estimation methods commonly used in EPA GHGRP reporting. For wells with plunger lifts, the emission estimates averaged 4500 scf/event as compared to an average of 8000 scf/event for the study measurements (difference is statistically different, $p = 0.004$). Despite the differences in mean predicted and observed emission rates, the paired measurements and estimates were weakly, but statistically significantly correlated. For wells without plunger lifts, the emission estimates averaged 31 000 scf/event as compared to an average of 27 000 scf/event for the measurements (difference is not statistically significant), however, while the averages are similar, the estimates were not well correlated with the observations. See SI (Section S4) for more details.

Implications for National Emission Estimates. National emissions, based on the measurements made in this work, are estimated by multiplying an emission factor, based on the measurements, by an activity factor. Emission event counts, stratified into categories based on emission events per year per well, were chosen for the activity factor because of the process used for selecting wells to be sampled and because annual emission estimates for wells with unloadings depended most strongly on event frequency.

As documented in SI (Section S1), the measurement team typically visited production Basins for approximately a week, and sampled randomly selected wells that had scheduled (for

manually triggered wells) or anticipated (for automatically triggered wells) unloading events for that week of sampling. This meant that the study team was far more likely to sample wells that unloaded weekly or more frequently, rather than wells that unloaded just a few times per year. This sampling approach resulted in a representative distribution of events, but not a representative distribution of wells. For example, 85% of the wells, without plunger lift, that have unloading emissions and that are operated by the companies that provided sampling sites in this work, had fewer than 10 emission events per year (See SI, Section S5). In the measurements performed for this work, 15 of the 32 wells without plunger lift (47%) had 10 or less events per year. These wells are therefore under-represented in the measurement data, relative to their presence in the participating companies' overall well population. Because of differences in the distributions of event frequency between the sampled wells and the national population of wells, it would not be appropriate to choose an emission factor of emissions per well per year and an activity factor of number of wells, without adjusting for this difference in event frequency distribution.

An additional reason for stratifying wells by frequency of events in the activity factor is the data shown in Figure 5, which indicate a reasonable degree of consistency in per event emissions. Wells without plunger lifts had measured mean values of 21 000–35 000 scf methane/event. Wells with plunger lifts had measured mean values of 1000–10 000 scf methane/event, but much larger ranges of event frequencies. For the calculations reported in this work, national, rather than regional averages of emissions per event will be used, due to the limited number of observations in individual regions.

In this work, national estimates of numbers of unloading events were based on a survey of the participating companies (see SI, Section S5). Data on event counts from the EPA GHGRP were not used since event counts for plunger and nonplunger wells are either partially reported or of uncertain quality. The national event counts were assumed to have the same distributions as reported in the participant survey. Based on this survey, it was estimated that the 32 225 wells with plunger lifts (based on data from the 2012 GHGRP) have a total of 6.8 million events per year. Only 206 500 of these 6.8 million events are associated with wells that vent less than 100 times per year. Total annual emissions from plunger lift wells are estimated at 10 billion cubic feet of methane per year (bcf/yr) (190 Gg/yr), with 80% of those emissions associated with wells that vent more than 100 times per year (additional details in SI, Section S5). For wells that vent more than 100 times per year, the average emissions per well per year are 1 400 000 scf per well per year (27 Mg/yr) with 95% confidence bounds of 600 000–2 500 000 scf (10–50 Mg, based on the confidence bounds in the emissions per event).

For wells without plunger lifts, it was estimated that 26 438 wells (based on data from the 2012 GHGRP) vent a total of 177 000 times per year, with total emissions of 4.4 bcf/yr (84 Gg/yr). Again, the wells that vent with highest frequency have the highest emissions per well. The 1.1% of wells that vent more than 50 times per year have average emissions of 3.2 million scf methane/yr. For wells without plunger lifts, however, these wells account for only 1.1% of the wells with unloading emissions, so the emissions from these wells venting at high frequency account for only 25% of emissions from wells without plunger lifts. Additional details are provided in SI, Section S5).

The overall emission estimate for liquid unloadings (plunger and nonplunger wells), based on the measurements made in this work, is 270 Gg (14 bcf/yr), which is within a few percent of the national emissions estimated in either the 2012 GHG NEI (273 Gg/yr) or the 2012 GHGRP (276 Gg/yr). The 95% confidence range for this estimate is 190–400 Gg/yr, based on the reported confidence ranges in the per event emission factors, but not accounting for uncertainties in event counts. SI (Section S5) reports sensitivity analyses that suggest uncertainties in event count estimates may be large, up to a factor of 2 or more, which could have a significant impact on national emission estimates. Regardless of the exact national total of emissions, however, wells with high frequencies of unloadings have annual emissions that are a factor of 10 or more greater than the annual emissions of wells with low frequencies of unloadings.

■ ASSOCIATED CONTENT

■ Supporting Information

Additional material as described in the text. This material is available free of charge via the Internet at <http://pubs.acs.org>.

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Notes

The authors declare the following competing financial interest(s): Lead author David Allen serves as chair of the Environmental Protection Agency's Science Advisory Board, and in this role is a paid Special Governmental Employee. He is also a journal editor for the American Chemical Society and has served as a consultant for multiple companies, including Eastern Research Group, ExxonMobil, and Research Triangle Institute. He has worked on other research projects funded by a variety of governmental, nonprofit and private sector sources including the National Science Foundation, the Environmental Protection Agency, the Texas Commission on Environmental Quality, the American Petroleum Institute and an air monitoring and surveillance project that was ordered by the U.S. District Court for the Southern District of Texas. Adam Pacsi and Daniel Zavala-Araiza, who were graduate students at the University of Texas at the time the work in this paper was done, have accepted positions at Chevron Energy Technology Company and Environmental Defense Fund, respectively. John Seinfeld served as a consultant for Shell in 2012. A. Daniel Hill owns ExxonMobil, BP, and ConocoPhillips stock, serves on the Advisory Board for Sanchez Oil and Gas, for which he is compensated, and has been a consultant for Schlumberger and numerous oil and gas operating companies..

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EDF's EXHIBIT BBB

REBUTTAL TESTIMONY OF TAMMY THOMPSON

I. DOCUMENTS REVIEWED

In preparing my rebuttal, I reviewed the following documents:

- Testimony of John Smitherman, NMOGA App'x A1;
- Direct Testimony of Ryan Davis, IPANM Ex. 2;
- Direct Testimony of Doug N. Blewitt, IPANM Ex. 6;
- Proposed Ozone Rule Comments, Doug N. Blewitt, IPANM Ex. 8;
- New Mexico Ozone Attainment Initiative Photochemical Modeling Study – Draft Final Air Quality Technical Support Document, NMED Ex. 17;
- Nolte *et al.*, The Potential Effects of Climate Change on Air Quality Across the Conterminous US at 2030 Under Three Representative Concentration Pathways, 18 Atmos. Chem. Phys. 15471-15489 (Oct. 2018) with supplement, EDF Ex. CCC; and
- Porter and Heald, The Mechanisms and Meteorological Drivers of the Summertime Ozone-Temperature Relationship, 19 Atmos. Chem. Phys. 13367-13381 (Oct. 2019), EDF Ex. DDD.

II. REDUCING VOC EMISSIONS IN AREAS THAT ARE NO_x-LIMITED CAN STILL IMPROVE AIR QUALITY

I reviewed NMOGA's claim that regulating volatile organic compounds (VOCs) in nitrogen oxide (NO_x)-limited areas would be "counterproductive," NMOGA App'x A1 at 4-5 and IPANM's claim that in NO_x-limited areas, ozone formation can only be "controlled by reducing NO_x emissions, not VOCs," IPANM Ex. 2 at 4. I disagree with the characterization that for areas deemed NO_x-limited, reducing VOC emissions will not reduce formation of ground-level ozone because NMED's modeling shows higher VOC sensitivity in locations of higher

ozone concentrations and consistently demonstrates a large contribution from oil and gas operations to high ozone levels.

The model clearly and consistently demonstrates a higher sensitivity of ozone formation to VOC emissions in the areas of highest ozone relative to the rest of the state. Ozone formation that is limited by the rate of any particular compound occurs on a continuum with NO_x-limited at one end and VOC-limited at the other, often called NO_x/VOC sensitivity. Very rarely is an area so far out on the spectrum that reductions of either VOC or NO_x will not have an impact on ozone formation. Further, NMED's modeling results consistently show that as locally produced ozone levels increase, anthropogenic VOCs become more impactful on ozone formation. An area that is NO_x limited will have a greater rate of production of hydroxide (OH) than NO_x production, meaning that the rate of ozone formation is dependent on NO_x emissions and, for an area that is completely NO_x limited, more effective reductions in ozone concentration can be achieved by reducing NO_x emissions. NMOGA and IPANM both conclude that this means that targeting VOC emissions in this area will have a limited or no impact on ozone formation. I strongly disagree as NO_x/VOC sensitivity is not a black and white issue and the model results consistently show that the higher the modeled ozone is, the less NO_x sensitive the formation is. Essentially, the highest ozone is the most VOC sensitive ozone, NMED Ex. 17 at 136, which underscores the need for NMED's proposed VOC controls.

As mentioned above, NO_x versus VOC limitation is not a black and white issue, and the sensitivity of ozone formation to each species can change by location, time of day and local and regional conditions. While NO_x is known to have the potential for ozone "disbenefit" (sometimes when NO_x emissions are in excess, reductions in NO_x can actually **increase** ozone because you are decreasing NO_x and ozone titration), VOC emissions reductions do not have

ozone disbenefits. VOC emissions will likely lead to ozone production eventually somewhere downwind, and so a reduction in VOC emissions will reduce ozone *somewhere*. Sometimes, depending on conditions, it will reduce ozone locally. There is no downside to reducing VOC emissions and with the constantly changing conditions that decide NO_x/VOC sensitivity, there will be ozone reductions at some point as a result of VOC emissions reductions. And modeling has shown that those ozone reductions from VOC emissions reductions are most likely to occur at the locations of the highest ozone concentrations.

III. LOCAL OIL AND GAS OPERATIONS CONTRIBUTE SIGNIFICANTLY TO OZONE NON-ATTAINMENT IN NEW MEXICO

NMED's ozone modeling show that oil and gas operations within New Mexico are the largest in-state contributor (by sector) to a number of high ozone days at monitors in danger of being designated non-attainment. Oil and gas operations in New Mexico contribute amounts of ground-level ozone that would arguably be subject to the provisions of EPA's good neighbor rule if the industry were its own state. NMOGA's and IPANM's assertion that oil and gas sources do not contribute significantly to ambient ozone concentrations is incorrect and is not supported by NMED's modeling.

NMED's modeled source apportionment shows that emissions from oil and gas sources in New Mexico consistently contribute more than 1 part per billion (ppb) to ozone monitors, and in many cases, comprise the largest in-state contribution by economic sector to ozone concentrations on high ozone days. NMED Ex. 17 at 112-27, 143-51. Indeed, the monitors in the Northwest portion of the state show the largest contribution from oil and gas sources and the highest sensitivity to VOCs. This conclusion strongly points towards the need for controls of VOCs and NO_x from oil and gas sources in New Mexico.

Notably, one way in which EPA regulates ozone transports is through its Good Neighbor rule, which requires any state contributing more than 1 ppb contribution to ozone non-attainment status in another state to reduce its emissions to help that downwind state achieve attainment of the ozone NAAQS. While the good neighbor rule does **not** impact the New Mexico counties being considered for regulation related to in-state locally emitted oil and gas emissions and the impact on in-state ozone (the good neighbor rule is only relevant to out of state sources and their impacts on in-state non-attainment monitors), it can be used to put the contribution from oil and gas production into context. If the oil and gas production sector were treated like a state, and if New Mexico becomes non-attainment, the emissions from this sector alone have a large enough contribution to high ozone at in-state monitors to trigger the good neighbor rule. Oil and gas production emissions contribute more on average on the ten highest ozone days at some monitors than the 1ppb threshold required to trigger the good neighbor rule.

IV. THE MODEL DOES NOT TAKE INTO ACCOUNT THE EFFECT OF A WARMING CLIMATE ON OZONE FORMATION AND THUS LIKELY UNDERESTIMATES FUTURE OZONE CONCENTRATIONS

Lastly, the model does not take into account a changing climate. Studies have predicted a phenomenon called an “ozone climate penalty” which means that as the climate changes and gets warmer and increasingly sunny/stagnant, ozone production will likely increase (all else being equal), resulting in a need for larger reductions to achieve the same ozone reduction numbers in a changing climate.¹ Our warming climate necessitates adoption of strong rules to reduce VOCs and methane, as NMED and EDF have proposed.

¹ Nolte, Christopher G. et al., The potential effects of climate change on air quality across the conterminous US at 2030 under three Representative Concentration Pathways, Atmospheric Chemistry and Physics (Oct. 29, 2018). EDF Ex. CCC.

Porter, William C. and Heald, Colette L., The mechanisms and meteorological drivers of the summertime ozone–temperature relationship, Atmospheric Chemistry and Physics (Oct. 30, 2019). EDF Ex. DDD.

EDF'S EXHIBIT CCC



The potential effects of climate change on air quality across the conterminous US at 2030 under three Representative Concentration Pathways

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Abstract. The potential impacts of climate change on regional ozone (O_3) and fine particulate ($PM_{2.5}$) air quality in the United States (US) are investigated by linking global climate simulations with regional-scale meteorological and chemical transport models. Regional climate at 2000 and at 2030 under three Representative Concentration Pathways (RCPs) is simulated by using the Weather Research and Forecasting (WRF) model to downscale 11-year time slices from the Community Earth System Model (CESM). The downscaled meteorology is then used with the Community Multiscale Air Quality (CMAQ) model to simulate air quality during each of these 11-year periods. The analysis isolates the future air quality differences arising from climate-driven changes in meteorological parameters and specific natural emissions sources that are strongly influenced by meteorology. Other factors that will affect future air quality, such as anthropogenic air pollutant emissions and chemical boundary conditions, are unchanged across the simulations. The regional climate fields represent historical daily maximum and daily minimum temperatures well, with mean biases of less than 2 K for most regions of the US and most seasons of the year and good representation of variability. Precipitation in the central and eastern US is well simulated for the historical period, with seasonal and annual biases generally less than 25 %, with positive biases exceeding 25 % in the western US throughout the year and in part of the eastern US during summer. Maximum daily 8 h ozone (MDA8 O_3) is projected to increase during summer and autumn in the cen-

tral and eastern US. The increase in summer mean MDA8 O_3 is largest under RCP8.5, exceeding 4 ppb in some locations, with smaller seasonal mean increases of up to 2 ppb simulated during autumn and changes during spring generally less than 1 ppb. Increases are magnified at the upper end of the O_3 distribution, particularly where projected increases in temperature are greater. Annual average $PM_{2.5}$ concentration changes range from -1.0 to $1.0 \mu g m^{-3}$. Organic $PM_{2.5}$ concentrations increase during summer and autumn due to increased biogenic emissions. Aerosol nitrate decreases during winter, accompanied by lesser decreases in ammonium and sulfate, due to warmer temperatures causing increased partitioning to the gas phase. Among meteorological factors examined to account for modeled changes in pollution, temperature and isoprene emissions are found to have the largest changes and the greatest impact on O_3 concentrations.

1 Introduction

In the United States (US), emissions that lead to the formation of ozone (O_3) and atmospheric particulate matter (PM) have declined significantly in recent decades, resulting in substantial improvements in air quality (Parrish et al., 2011; US EPA, 2012) and consequent benefits for human health (Pope III, 2007; Correia et al., 2013). As a result of regulatory actions, such as the Cross-State Air Pollution Rule and

the Tier 2 and Tier 3 emissions standards for motor vehicles, anthropogenic emissions are projected to continue their downward trend through 2030 (US EPA, 2015), leading to further reductions in ambient O₃ and concentrations of PM particles smaller than 2.5 µm in diameter (PM_{2.5}).

Because air pollution is highly sensitive to meteorology, climate change has the potential to affect air quality by modifying temperatures, wind speeds, mixing heights, humidity, clouds, and precipitation, which all affect pollutant formation and removal rates (Jacob and Winner, 2009; Tai et al., 2010; Fiore et al., 2015; Westervelt et al., 2016). Studies using global climate model (GCM) data to drive global or regional chemical transport models (CTMs) have found that climate change yields meteorological conditions that are more conducive to forming high O₃, exacerbating summertime O₃ over polluted continental regions (Mickley et al., 2004; Leung and Gustafson Jr., 2005; Stevenson et al., 2006; Katragkou et al., 2011; Horton et al., 2012; Gao et al., 2013). Modeling studies conducted using mid-21st century climate data project up to 2–8 ppb increases in summer average ozone levels in the US, depending on climate change scenario and time period (e.g., Wu et al., 2008; Nolte et al., 2008; Weaver et al., 2009; Kelly et al., 2012; Trail et al., 2014; Pfister et al., 2014; Gonzalez-Abraham et al., 2015; Fann et al., 2015; He et al., 2016; Dionisio et al., 2017). This deterioration of air quality due to climate change is known as the “climate penalty” (Wu et al., 2008; Rasmussen et al., 2013) and could potentially offset some of the improvement in air quality that would otherwise occur due to reductions in ozone precursor emissions. The strong evidence for the increase in surface O₃ levels due to climate change was cited in support of the finding that emissions of greenhouse gases (GHGs) endanger human health and welfare and are therefore subject to regulation in the US under the Clean Air Act (US EPA, 2009). The net effects of climate change on PM_{2.5} are more uncertain. Some studies that have investigated the impacts of climate change on PM_{2.5} have found small but statistically significant effects of 0.5–2.0 µg m⁻³, but with little consistency, even in the sign of the change (Liao et al., 2006; Racherla and Adams, 2006; Heald et al., 2008; Pye et al., 2009; Kelly et al., 2012; Tai et al., 2012; Dawson et al., 2014; Day and Pandis, 2015; Fiore et al., 2015; Shen et al., 2017). It should be noted, however, that most studies of climate change impacts on PM_{2.5} have neglected changes in climate-sensitive PM emissions sources. The studies that have considered changes in these sources have concluded that warmer temperatures and earlier snowmelt associated with climate change will lead to increased impacts from wildfires (Spracklen et al., 2009; Val Martin et al., 2015; Liu et al., 2016) and dust storms (Achakulwisut et al., 2018).

Motivated by high positive biases (exceeding 10 ppb) in present-day O₃ obtained in previous work (Nolte et al., 2008), which were attributed to positive biases in temperature in the downscaled meteorology, we developed improved

regional climate modeling techniques that were tested by downscaling coarse reanalysis data (Bowden et al., 2012, 2013; Otte et al., 2012) and using the downscaled meteorology to simulate air quality (Seltzer et al., 2016). In the present study, we apply this downscaling methodology to GCM data and use the resulting regional climate fields to drive simulations of air quality across the conterminous US. The near-future timeframe of 2030 is chosen because of its relevance for air quality policy and the current planning horizon. Lateral boundary conditions and anthropogenic emissions are identical for both the historical and future periods to isolate the meteorological influences of near-term climate change on regional air quality. The simulated historical regional climate is evaluated by comparison to reanalysis fields. Changes in regional climate and air quality at 2030 are presented, and we relate the changes in air quality to the meteorological drivers for these changes.

Previous studies of the effects of climate change on air quality have typically considered a single climate scenario (Trail et al., 2014; Gonzalez-Abraham et al., 2015), period of a few years (Nolte et al., 2008; Gao et al., 2013; Penrod et al., 2014) or a single season (Kelly et al., 2012; Pfister et al., 2014; Day and Pandis, 2015; Gonzalez-Abraham et al., 2015). This study examines the impact of climate change on both ozone and PM air quality for the full annual cycle using 11-year periods with three GHG trajectories. In addition to presenting changes in seasonal mean quantities, we also focus on distributions and examine variability across seasonal and diurnal temporal scales.

2 Modeling approach

2.1 Global climate model

The GCM used in this study is the National Center for Atmospheric Research-Department of Energy Community Earth System Model (CESM) (Gent et al., 2011). The model has horizontal grid spacing of 0.9° latitude × 1.25° longitude. Time slices of 11-year periods from simulations conducted for the fifth phase of the Coupled Model Intercomparison Project (CMIP5) (Taylor et al., 2012) were selected for downscaling: 1995–2005 at the end of the CMIP5 historical 20th century simulation, as well as 2025–2035 from simulations following three Representative Concentration Pathways (RCPs; van Vuuren et al., 2011). The RCP8.5 scenario (Riahi et al., 2011) assumes “business as usual”, where GHG concentrations increase substantially over the 21st century, leading to 8.5 W m⁻² radiative forcing by 2100. The RCP6.0 scenario (Masui et al., 2011) assumes a modest degree of mitigation of GHG emissions, where total radiative forcing increases before stabilizing at 6.0 W m⁻² in 2100. The RCP4.5 scenario (Thomson et al., 2011) has a GHG emissions peak in the middle of the 21st century followed by a decline, so that total radiative forcing is 4.5 W m⁻² in 2100. Although

the RCP scenarios are named for their radiative forcing at the year 2100, the GHG emissions paths in each scenario were developed by independent modeling groups. As a result, a lower RCP scenario may have higher GHG emissions and a greater increase in global average temperature than a higher RCP scenario for the 2025–2035 period examined here (Collins et al., 2013).

2.2 Regional climate model

The CESM data were downscaled with the Weather Research and Forecasting (WRF) model (Skamarock and Klemp, 2008) version 3.4.1 to a domain with 36 km horizontal grid spacing covering most of North America (199×127 grid points; Fig. 1) and 34 vertical layers extending to a model top at 50 hPa. Archived 6 h fields used for downscaling included 3-D temperature, specific humidity, horizontal wind components, pressure, and geopotential height; 2-D surface pressure, skin temperature, 2 m temperature, and 2 m specific humidity; and monthly average sea surface temperatures, ice fraction, soil moisture, and soil temperature. To avoid water temperature discontinuities that arise from applying GCM ocean temperatures to large lakes (Mallard et al., 2015), monthly lake temperature data from the land component of CESM (i.e., the Community Land Model, CLM) were used to set the temperature of inland water points on the regional domain (Spero et al., 2016). All monthly fields were temporally interpolated to 6 h intervals to avoid abrupt transitions in the regional climate simulations.

WRF was initialized at 00:00 UTC 1 October 1994 for the historical run and at 00:00 UTC 1 October 2024 for each of the RCP runs, so that each regional climate simulation included a 3-month spin-up period. Land use classification was based on the 24-category USGS land cover database. WRF was configured as in Spero et al. (2016), with spectral nudging of horizontal wind components, potential temperature, and geopotential applied above the planetary boundary layer (PBL) using the nudging coefficients from Otte et al. (2012).

2.3 Chemical transport model

The chemical transport model used was the Community Multiscale Air Quality (CMAQ) model (<https://www.epa.gov/cmaq>, last access: 25 October 2018) version 5.0.2 (Byun and Schere, 2006; Carlton et al., 2010; Appel et al., 2013; US EPA, 2014a). The model was configured with the multipollutant version of the Carbon Bond 2005 gas phase chemical mechanism (cb05tump) and the AERO6 aerosol module (Simon and Bhawe, 2012; Nolte et al., 2015). CMAQ simulations were conducted over a 36 km domain covering the conterminous US (148×110 grid cells; Fig. 1). The Meteorology-Chemistry Interface Processor (MCIP) (Otte and Pleim, 2010) version 4.1.3 was used to prepare meteorological fields for CMAQ using the same vertical layering

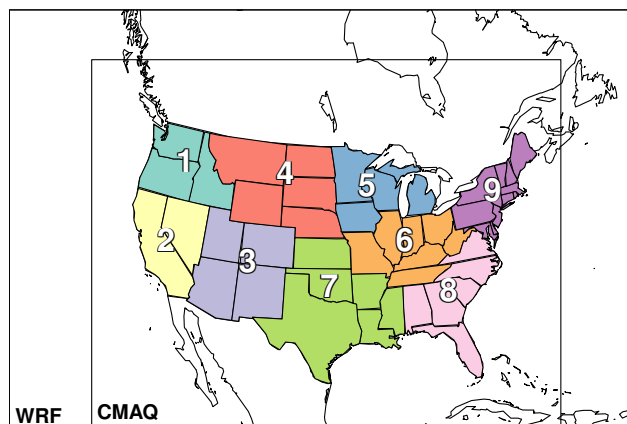


Figure 1. WRF and CMAQ modeling domains, with colored areas representing the National Centers for Environmental Information (NCEI) US climate regions used for evaluation: (1) Northwest, (2) West, (3) Southwest, (4) Northern Rockies and plains, (5) Upper Midwest, (6) Ohio Valley, (7) South, (8) Southeast, and (9) Northeast.

as in WRF. Reported pollutant concentrations are taken from the lowest model layer, which has a depth of about 38 m. Each 11-year CMAQ simulation was run continuously following a 10-day spin-up period.

Numerous studies using regional CTMs that have considered both changing climate and changing emissions on future air pollutant concentrations have found that changes in emissions dominate (Nolte et al., 2008; Kelly et al., 2012; Colette et al., 2013; Trail et al., 2014; Day and Pandis, 2015; Gonzalez-Abraham et al., 2015; He et al., 2016). Modeled pollutant concentrations are highly sensitive to lateral chemical boundary conditions (e.g., Tang et al., 2007; Kastragkou et al., 2010; Schere et al., 2012), and different assumptions regarding changes in long-range transport have been shown to have a significant impact on future pollutant levels (Nolte et al., 2008; Colette et al., 2013; Pfister et al., 2014; Gonzalez-Abraham et al., 2015; He et al., 2016; Zhang et al., 2016). Several previous studies have also highlighted the importance of rising levels of methane for ozone chemistry (Fiore et al., 2002; West and Fiore, 2005; Nolte et al., 2008). To isolate the effects of climate change on air quality, only the meteorological conditions and the meteorologically dependent emissions that are modeled within CMAQ were modified between the historical and future CMAQ simulations. All other input variables, including anthropogenic emissions, chemical lateral boundary conditions, and land use and land cover classifications, were unchanged across the air quality modeling scenarios.

Anthropogenic air pollutant emissions for each year of both the historical and future periods were modeled using the 2030 emissions projection that was used as the reference case for the Tier 3 motor vehicle standards rulemaking analyses (US EPA, 2014b, c). This projection assumed the

implementation of previously adopted air quality policies, with the result that anthropogenic NO_x , SO_2 , and volatile organic compound (VOC) emissions are 54 %, 69 %, and 25 % lower, respectively, than in the 2011 National Emissions Inventory (Table S1 in the Supplement). Biogenic VOC emissions were modeled using the Biogenic Emission Inventory System (BEIS) (Carlton and Baker, 2011) and thus responded to climate-driven meteorological changes. Monthly and diurnal temporal profiles were applied to other emissions source sectors, including wildfires, but did not vary across years. Emissions of NO_x due to lightning were not modeled. Chemical lateral boundary conditions derived from an independent simulation of the year 2011 by the GEOS-Chem global chemical transport model (Bey et al., 2001; Henderson et al., 2014) were used for each year of the historical and the RCP simulations.

3 Evaluation for historical period

The CMAQ modeling system has been extensively evaluated for simulation of historical (“retrospective”) air quality (Foley et al., 2010; Appel et al., 2013, 2017). It is challenging, however, to evaluate air quality simulated using meteorology downscaled from a global climate model (Menut et al., 2013; Seltzer et al., 2016). Because climate models are run without assimilating weather observations, the weather conditions simulated by downscaling a GCM for a particular historical day cannot be expected to correspond to the hourly meteorology that occurred on that day. For the same reason, it is inappropriate to evaluate air pollutant concentrations simulated using downscaled meteorology against hourly or daily historical measurements. Instead, regional climate and air quality should be evaluated at seasonal and monthly temporal scales. As a further complication, to account for interannual meteorological variability it is necessary to run the model for periods of several years or even decades, but anthropogenic emissions of pollutants such as NO_x , VOC, and SO_2 can exhibit significant trends that confound the analysis of the impact of using downscaled meteorology. An evaluation of 2000–2010 ozone and $\text{PM}_{2.5}$ air quality simulated using historical emissions and meteorology downscaled from a coarse-scale historical reanalysis showed a performance comparable to that obtained in typical air quality modeling applications (Seltzer et al., 2016). This demonstrates that the downscaling procedure does not introduce substantial bias into the modeled air quality, providing confidence in the method’s use for future air quality projections.

Because this study uses projected 2030 emissions in all simulations, including for the historical period, modeled air quality is not compared to observations. Instead the evaluation of the historical period is focused on monthly and seasonal means and selected percentiles of regional temperature and precipitation, two meteorological fields that strongly affect air quality. Temperature and precipitation from the his-

torical period are evaluated by comparing against the Climate Forecast System Reanalysis (CFSR; Saha et al., 2010) and the North American Regional Reanalysis (NARR; Mesinger et al., 2006), respectively. CFSR is a global reanalysis with hourly 2 m temperature at 0.31° resolution, enabling evaluation of daily maximum and daily minimum temperatures. NARR is used to evaluate precipitation because it has been shown to represent precipitation well over the conterminous US (Bukovsky and Karoly, 2007), while CFSR precipitation is positively biased (Otte et al., 2012). Regional analysis is performed using US climate regions defined by the National Centers for Environmental Information (Fig. 1).

Seasonal averages of daily mean 2 m temperatures simulated by downscaling CESM with WRF are compared against CFSR fields horizontally interpolated to the WRF grid in Fig. 2. The seasonal and spatial patterns of 2 m temperatures are generally well represented by WRF, though in areas of complex terrain in the western US there are positive and negative biases exceeding 4 K (Fig. 2). Daily minimum temperatures are within ± 2 K of CFSR for every region and season except during summer (JJA) in the Northwest and West regions (see Fig. 1 for the region designations), which have warm biases of 2.7 and 3.4 K, respectively. Daily maximum temperatures are also generally well simulated, with absolute biases only exceeding 2 K for the Southwest during spring (MAM), the Upper Midwest during spring, summer, and autumn (SON), and for the Northeast during spring and autumn (Fig. 3). Though these regionally averaged temperature biases are somewhat larger than those typically obtained in retrospective meteorological modeling for air quality applications, they are comparable to biases reported in dynamically downscaled meteorology utilizing nudging (e.g., Trail et al., 2013; Gonzalez-Abraham et al., 2015; Colette et al., 2013). We note that these biases in the downscaled regional climate fields are largely attributable to the driving CESM fields rather than to errors within WRF (see Supplement).

Distributions of the daily maximum 2 m temperatures simulated by WRF for each region and month over the historical 1995–2005 period in comparison to CFSR are shown in Fig. 3; regional distributions of daily minimum 2 m temperatures are provided in the Supplement. The downscaled simulations using WRF reasonably capture the regional variation in the annual cycle of median values as well as the width of the interquartile range (IQR). Narrower distributions are simulated during summer than winter, in agreement with the pattern in CFSR, but WRF accentuates this difference in some regions, with excessively narrow daily maximum temperature distributions simulated in the Upper Midwest, Northeast, Ohio Valley, South, and Southeast. For maximum temperatures, the WRF simulations of the Northwest and the Northern Rockies regions have the best overall agreement with CFSR. Though maximum temperatures are negatively biased most of the year in the Southwest and West, the magnitude of the IQR is well represented in those regions. During the summer, the IQR of daily maximum temperatures in WRF

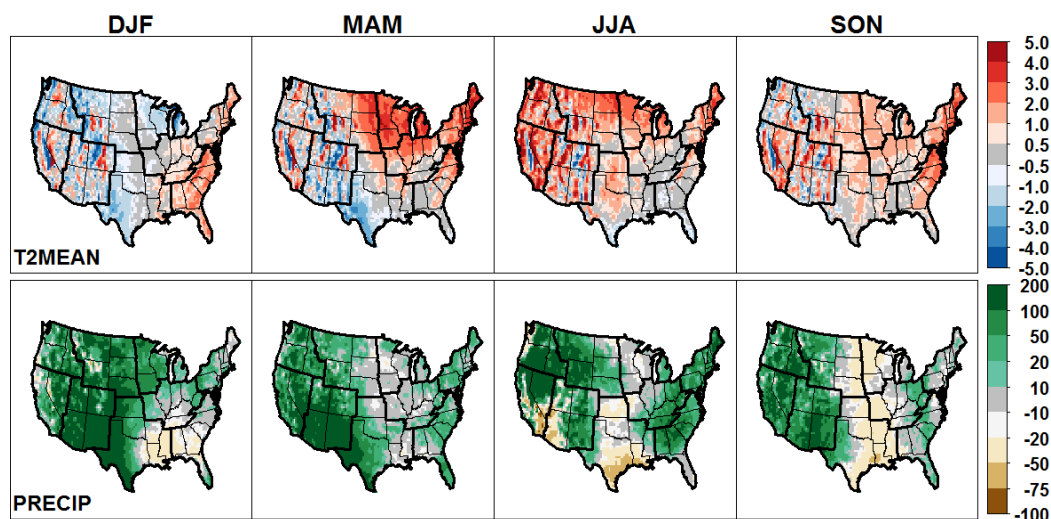


Figure 2. Seasonally averaged biases in daily mean 2 m temperature compared to CFSR (K) and precipitation relative to NARR (%), simulated by downscaling CESM with WRF for 1995–2005.

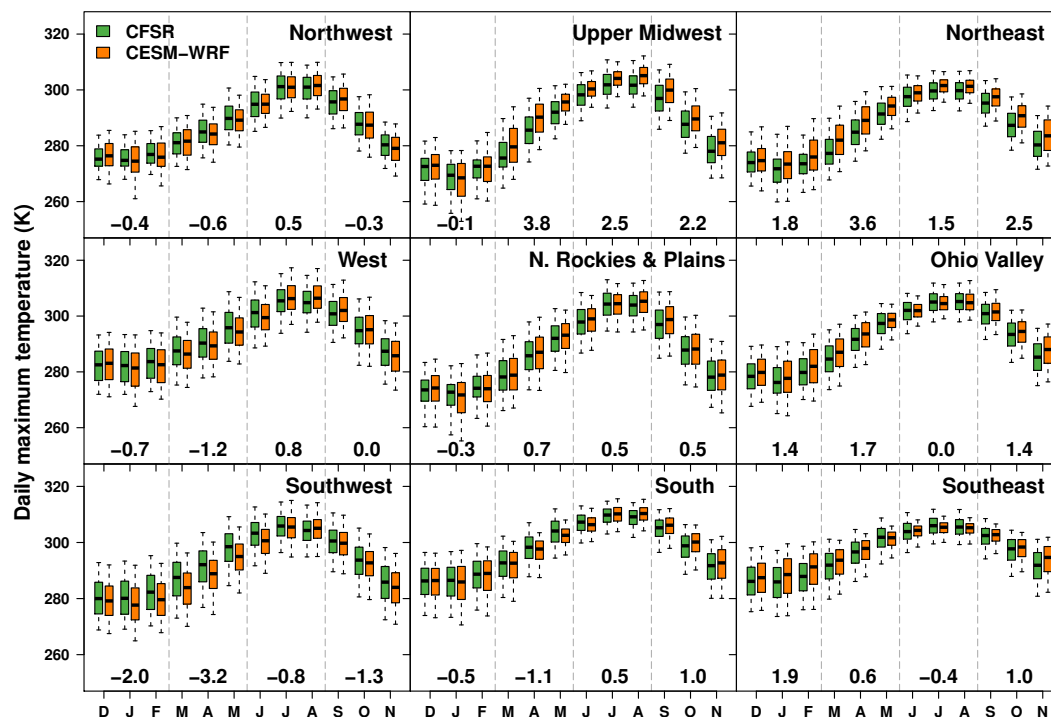


Figure 3. Monthly box plots of daily maximum 2 m temperature simulated by downscaling CESM with WRF for the historical 1995–2005 period compared against CFSR for each of the US climate regions shown in Fig. 1. Boxes range from the 25th to 75th percentiles with the dark line denoting the median, and whiskers extend to 5th and 95th percentiles. Seasonal biases (K) are shown at bottom.

is much lower than in CFSR in several regions, including the Upper Midwest, South, Ohio Valley, and Southeast. In the regions and months with the largest biases, the distribution is shifted by nearly a quartile. The worst performance is in August in the Upper Midwest, in which the 25th and 50th percentile daily maximum temperatures simulated by

WRF exceed the median and 75th percentile CFSR values, respectively.

The spatial and seasonal distributions of precipitation across the conterminous US in WRF are broadly consistent with NARR (Fig. 2). WRF generally has a wet bias relative to NARR, except for the South, Upper Midwest, and Ohio

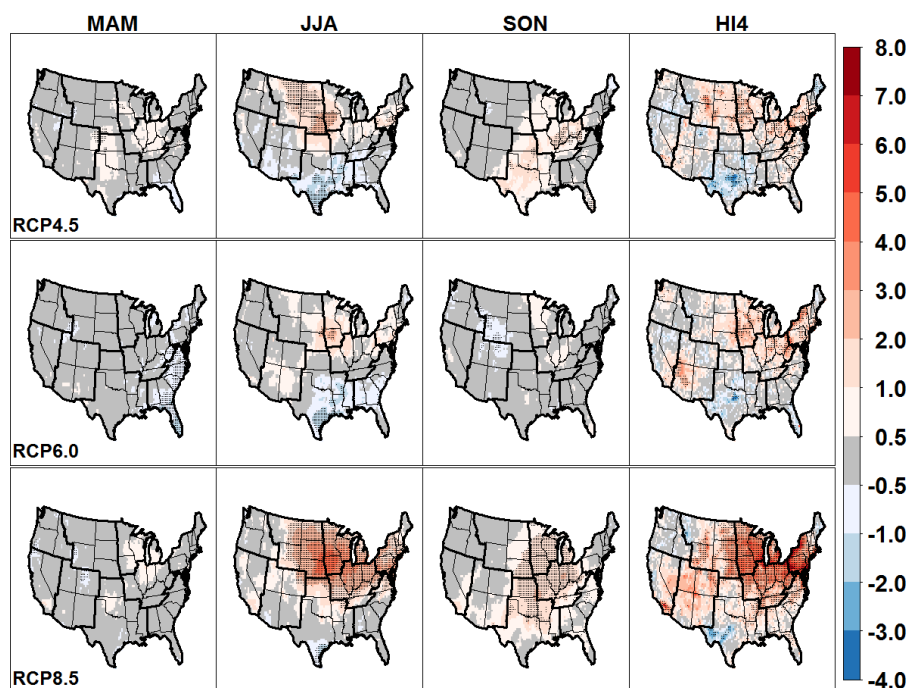


Figure 4. Projected changes in maximum daily 8 h average (MDA8) O₃ mixing ratios (ppb) from 1995–2005 to 2025–2035 under RCP4.5, RCP6.0, and RCP8.5 (in rows). Columns show projected changes for spring, summer, and autumn seasonal means, as well as fourth-highest annual values (“HI4”). Dark pixels indicate where differences are significant according to Student’s *t* test ($p < 0.05$).

Valley regions. Regional biases relative to NARR are given in Table 1. Precipitation is reasonably well simulated in the central and eastern US, with most seasonal and annual biases 25 % or less. In the western US, however, WRF precipitation is positively biased relative to NARR throughout the year, particularly in the Southwest during winter and spring and in the West and Northwest regions during summer. A less severe positive bias in precipitation also exists during the summer in the eastern US north of Florida.

4 Changes at 2030 under RCPs

Potential changes in seasonal mean air pollutant concentrations are presented under the three RCPs for 2025–2035 relative to 1995–2005. Next, the meteorological drivers influencing the changes in air quality are examined.

4.1 Ozone

Changes in seasonal mean maximum daily 8 h average (MDA8) O₃ levels for spring, summer, and autumn are shown in Fig. 4; plots showing absolute magnitudes are provided in the Supplement. The general locations of the seasonal changes are consistent across the three RCP scenarios, although the magnitudes are less pronounced under RCP4.5 and RCP6.0, as expected. Statistically significant increases of 1–5 ppb are simulated during summer under RCP8.5 across most of the northern and eastern US, with regional average

Table 1. Seasonally and regionally averaged biases in accumulated precipitation (%) in comparison to NARR for 1995–2005.

Region	DJF	MAM	JJA	SON	Annual
Northwest	34	41	118	51	48
West	27	70	151	80	54
Southwest	175	132	41	80	97
Northern Rockies	66	20	53	13	36
Upper Midwest	35	−1	1	−16	0
Ohio Valley	5	4	33	−3	11
South	17	25	−17	−20	0
Southeast	−5	23	41	13	20
Northeast	14	23	65	7	28

increases of at least 2 ppb across the Northern Rockies, Upper Midwest, and Ohio Valley (Table 2). Summer decreases of up to 1.5 ppb are projected in the South and Southeast regions, particularly along the Texas Gulf Coast. The summer decrease is widespread under RCP4.5 and RCP6.0, averaging 0.4–0.5 ppb across the South and Southeast regions.

The projected impact of climate change on MDA8 O₃ is lower during the spring and autumn seasons than in summer under all three RCPs. For the spring, small increases of 0.5–1.0 ppb are simulated over parts of the Ohio Valley, South, and Upper Midwest regions under RCP4.5 and RCP8.5, which generally are not statistically significant. Statistically significant decreases of 0.5–1.0 ppb are simulated

Table 2. Changes in maximum daily 8 h O₃ by region.

Region	RCP4.5				RCP6.0				RCP8.5			
	MAM	JJA	SON	HI4	MAM	JJA	SON	HI4	MAM	JJA	SON	HI4
Northwest	−0.1	0.2	−0.1	0.1	−0.2	0.0	−0.3	0.3	−0.3	0.2	−0.1	0.0
West	−0.1	−0.2	0.1	0.1	−0.1	−0.1	0.1	0.2	0.0	0.4	0.3	1.1
Southwest	0.2	−0.2	0.2	0.4	0.1	0.4	−0.2	0.6	−0.1	0.5	0.5	1.6
Northern Rockies	0.1	1.3	0.0	1.1	−0.2	0.5	−0.1	0.6	−0.0	2.0	0.5	1.6
Upper Midwest	0.4	0.7	0.6	1.4	−0.3	1.0	0.5	1.7	0.4	2.9	1.3	3.8
Ohio Valley	0.5	0.2	0.9	1.0	−0.3	0.4	0.4	1.2	0.3	2.1	1.4	3.1
South	0.2	−0.4	0.8	−0.5	−0.1	−0.5	0.0	−0.1	0.1	0.4	1.0	0.6
Southeast	−0.1	−0.4	0.3	0.7	−0.7	−0.4	0.1	0.2	−0.0	0.2	0.5	1.2
Northeast	0.2	0.6	0.1	1.1	−0.4	0.5	−0.2	1.5	0.2	1.8	0.2	3.3
All US	0.2	0.2	0.4	0.5	−0.2	0.1	0.0	0.6	0.0	1.1	0.7	1.6

along the Southeast coast in RCP6.0. During the autumn, significant increases of 1–2 ppb are simulated across a broad area of the central US including most of the South, Ohio Valley, and Upper Midwest regions under both RCP8.5 and RCP4.5, but no significant change is evident under RCP6.0.

The preceding analysis focused on changes in seasonal mean MDA8 O₃. Because compliance with the US National Ambient Air Quality Standard (NAAQS) for O₃ is assessed using the annual fourth-highest MDA8 O₃ (“HI4”), changes in HI4 averaged across the 11-year periods are also shown in Fig. 4 and Table 2. Under RCP8.5, regional average increases in HI4 exceeding 3 ppb are simulated for the Upper Midwest, Ohio Valley, and Northeast, with increases exceeding 5 ppb over large areas within those regions as well as parts of the Southwest and West. Under RCP4.5 and RCP6.0, regional average HI4 increases by 1.0–1.7 ppb in the Upper Midwest, Ohio Valley, and Northeast, exceeding 3 ppb through large parts of those regions. The modeled increases in HI4 under all three RCPs examined in the Upper Midwest, Ohio Valley, and Northeast regions, which are highly populated areas of the US, have potentially significant implications for human health and NAAQS compliance.

Some previous observational (Porter et al., 2015) and modeling studies (Weaver et al., 2009; Jacob and Winner, 2009; Pfister et al., 2014; Rieder et al., 2015) have found that extreme O₃ values have a greater sensitivity to temperature than do mean values. Projected changes across the O₃ distribution are examined using seasonal percentiles that are calculated for each grid cell, then averaged across regions and years for the historical and future climate periods (Fig. 5). In summer in the Northeast, Ohio Valley, and Southeast, the change in O₃ under each of the RCPs is projected to be greater at the upper end of the distribution. In the South and Southeast, there is a projected decrease of 0.5–1.0 ppb at the lower end of the distribution under all three RCPs. A gradual increase is projected in the slope through the 90th percentile, with more pronounced increases at the upper tail. By contrast, the projected change in O₃ is comparatively uni-

form across the distribution in the Northern Rockies region, while there is little change at any part of the distribution in the Northwest, West, and Southwest regions. During autumn under RCP8.5, increases ranging from 1 ppb at the low end of the distribution to 2 ppb at the high end are projected in the Upper Midwest and Ohio Valley regions, while changes under RCP4.5 and RCP6.0, as well as changes during spring under each of the RCPs, are less than 1 ppb throughout the distribution for each region (Supplement).

To investigate changes over the entire annual cycle, regional monthly box plots of MDA8 O₃, simulated for the historical period and the RCP8.5 simulation, are compared in Fig. 6. Analogous comparisons with the RCP4.5 and RCP6.0 runs are included in the Supplement. Consistent with Fig. 5, the largest changes in median values are projected in the Upper Midwest, Northern Rockies, Northeast, and Ohio Valley regions during the summer. Though some of the highest extreme MDA8 O₃ values are simulated in the West and Southwest, changes in those regions are comparatively small. While most previous studies of the effect of climate change on O₃ pollution have emphasized the summer, when O₃ concentrations are highest, a few investigators have reported increases during spring and autumn, suggesting a lengthening of the ozone season (Fiore et al., 2002; Nolte et al., 2008; Trail et al., 2014). Clifton et al. (2014) have projected a reversal of the O₃ seasonal cycle in the northeastern US by the end of the 21st century, with increased methane levels and decreased NO_x levels combining to produce a wintertime maximum in surface O₃. Here we find that median, 75th, and 98th percentile MDA8 O₃ values increase in nearly every region of the US during October, November, and December under the RCPs, but do not show a consistent response during the months January through May.

4.2 Particulate matter

Projected changes in annual mean concentrations of total PM_{2.5} and its largest components under the three RCPs are shown in Fig. 7, while absolute quantities for the historical

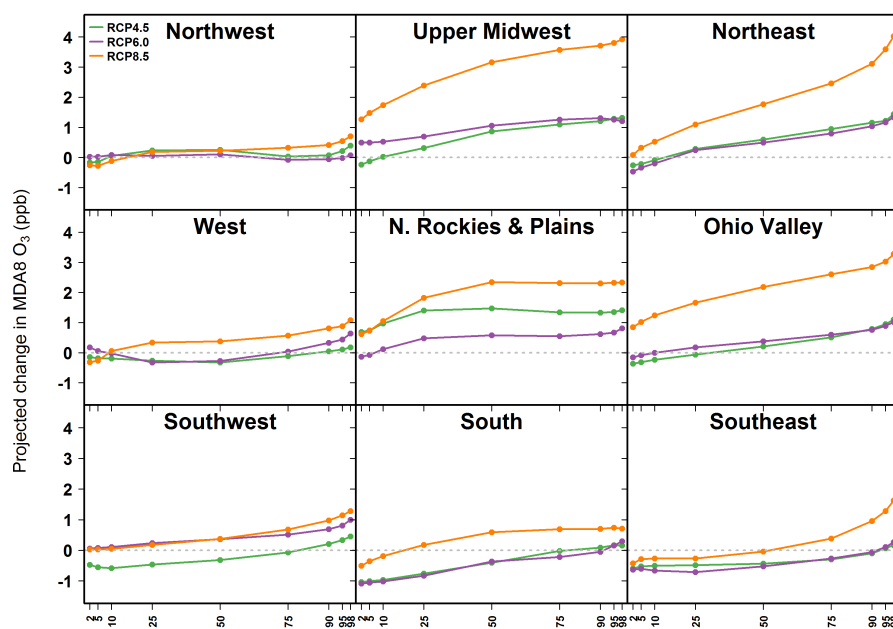


Figure 5. Projected changes in percentiles of summer average MDA8 O₃ mixing ratios (ppb) simulated by CMAQ under RCP4.5, RCP6.0, and RCP8.5 within each of the US climate regions shown in Fig. 1.

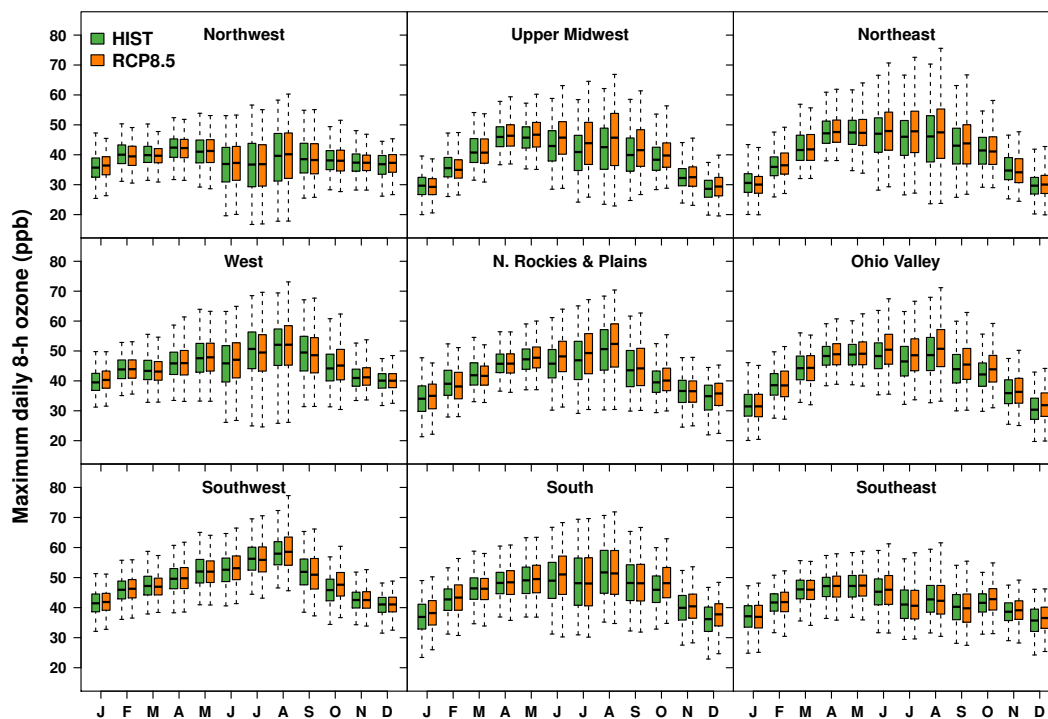


Figure 6. Monthly box plots of MDA8 O₃ simulated for the historical 1995–2005 period and 2025–2035 under RCP8.5 for each of the US climate regions shown in Fig. 1. Boxes range from the 25th to 75th percentiles with the dark line denoting the median, and whiskers extend to 2nd and 98th percentiles.

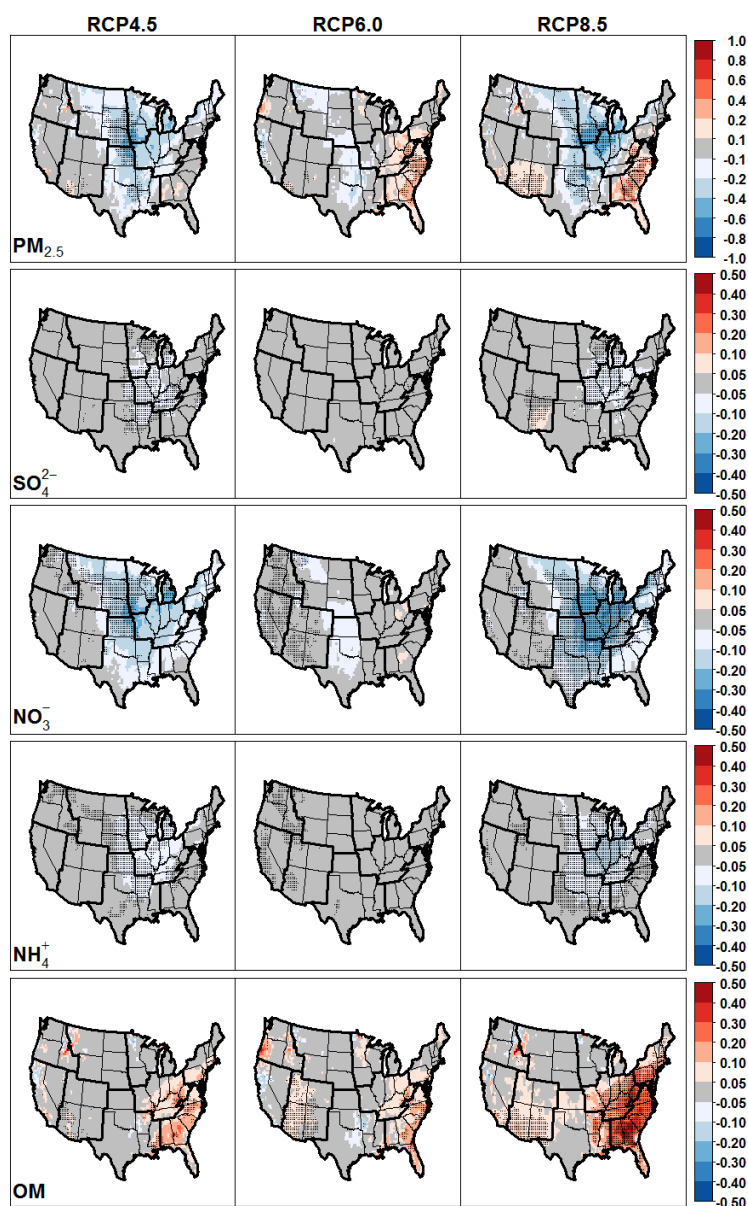


Figure 7. Projected changes in annual mean concentrations ($\mu\text{g m}^{-3}$) of total PM_{2.5} and principal PM_{2.5} components from 1995–2005 to 2025–2035 under RCP4.5, RCP6.0, and RCP8.5. Dark pixels indicate where differences are significant according to Student's *t* test ($p < 0.05$).

period and relative changes are provided in the Supplement. Statistically significant PM_{2.5} decreases of up to $0.7 \mu\text{g m}^{-3}$ (5 %–10 %) are simulated in the Northern Rockies and Ohio Valley regions under RCP8.5 and RCP4.5, while increases of up to $1.0 \mu\text{g m}^{-3}$ occur in the Southeast under RCP8.5 and RCP6.0. Most of the decreases in PM_{2.5} are due to decreases in nitrate (NO_3^-) of up to $0.4 \mu\text{g m}^{-3}$ (40 %). The decreases in NO_3^- are accompanied by lesser decreases in ammonium (NH_4^+) and sulfate (SO_4^{2-}). Increases in PM_{2.5} in the Southeast are largely attributable to organic matter (OM), which increases up to $0.5 \mu\text{g m}^{-3}$ (10 %–20 %).

Seasonally averaged changes in NO_3^- and OM are shown in Figs. 8–9; the patterns of seasonal changes in SO_4^{2-} and NH_4^+ (Supplement) are similar to the changes in NO_3^- . The decreases in annual average NO_3^- levels under RCP8.5 and RCP4.5 (Fig. 7) are driven by decreases during winter and spring (Fig. 8). The decrease is strongest during winter under RCP8.5, when average NO_3^- concentrations decrease by $0.3\text{--}0.9 \mu\text{g m}^{-3}$ over most of the eastern US. By contrast, the increases in OM primarily occur during summer and autumn (Fig. 9). During summer under RCP8.5, projected changes to OM are most pronounced in the Southeast and

Ohio Valley regions, where there are projected increases of $0.2\text{--}0.8\ \mu\text{g m}^{-3}$. There are less pronounced increases of $0.1\text{--}0.3\ \mu\text{g m}^{-3}$ in those regions under RCP4.5 and RCP6.0.

4.3 Meteorological influences on projected changes in air quality

Because the anthropogenic emissions and chemical lateral boundary conditions are the same in all CMAQ simulations, all projected changes in air quality are due to differences in meteorology downscaled from the climate scenarios. To gain insight into the parameters most strongly influencing the changes in air quality, correlation coefficients were calculated between monthly mean changes in several meteorological variables and changes in pollutant concentrations, focusing on the species and seasons where the impacts of climate change were greatest. Variables examined included daily mean, maximum, and minimum 2 m temperatures; daily mean and daily maximum PBL heights; precipitation; cloud cover; 10 m wind speeds; number of days with stagnant meteorological conditions (Wang and Angell, 1999; Horton et al., 2012); and biogenic isoprene emissions. The variables with the strongest correlations to changes in O_3 were daily maximum 2 m temperature, isoprene emissions, and cloud cover, while temperature, isoprene, and stagnation had the strongest correlations with NO_3^- and OM (Supplement).

Projected changes in seasonally averaged daily maximum 2 m temperatures are shown in Fig. 10. As expected, the temperature increase is greatest under RCP8.5. In RCP8.5, daily maximum temperatures increase by 0.5 K across most of the conterminous US in all seasons, by more than 2 K in the South, Upper Midwest, and Ohio Valley regions during winter, and by more than 3 K in much of the Upper Midwest and Ohio Valley regions during summer. Under RCP4.5, daily maximum temperatures increase by $0.5\text{--}3.0\ \text{K}$ in most of the conterminous US throughout the year, with the largest and most widespread increase projected during spring. By contrast, the changes in daily maximum temperatures under RCP6.0 are less pronounced, with summertime increases of $1\text{--}3\ \text{K}$ over most of the US but little change in the eastern US during autumn, and even slight cooling of $0.5\text{--}1.0\ \text{K}$ projected in parts of the Southeast and Ohio Valley regions during winter. Across the conterminous US, annual average daily maximum temperatures increase by 1.2 K under RCP4.5, 0.7 K under RCP6.0, and 1.7 K under RCP8.5.

The spatial patterns of the mean changes in winter and spring daily maximum temperatures in the RCPs (Fig. 10) correspond to the changes in NO_3^- concentrations (Fig. 8), and monthly variations in NO_3^- and maximum temperatures are strongly negatively correlated (Supplement). Aerosol NO_3^- increases in the portions of the Southeast and the Ohio Valley regions where wintertime daily maximum temperatures decrease slightly under RCP6.0. The patterns of changes in aerosol NH_4^+ concentrations (Supplement) largely

mirror the changes in NO_3^- . There is little decrease in aerosol NO_3^- during summer because nitrate exists almost totally in the gas phase during that season.

While anthropogenic emissions are unchanged across these simulations, biogenic emissions of VOCs are modeled within CMAQ and respond to changes in meteorology. Isoprene emissions depend on temperature as well as photosynthetically active radiation, which is attenuated in the presence of clouds. Modeled emissions of biogenic isoprene increase across all future scenarios, due to both warmer temperatures and decreased cloudiness (Fig. 12). Modeled average annual isoprene emissions over the conterminous US increase by 11 %, 8 %, and 19 %, under RCP4.5, RCP6.0, and RCP8.5, respectively. The increased emissions of isoprene and other biogenic VOCs in the heavily forested Southeast region not only enhance production of O_3 (Fig. 4), but also account for most of the increases in OM concentrations (Fig. 9).

Scavenging of soluble aerosols by precipitation is an important removal process for atmospheric particulate matter. Shown in Fig. 11 are percent changes in seasonal precipitation for each of the RCP scenarios. The decrease in summer and autumn precipitation in the South, Southeast, and Ohio Valley regions under all three climate scenarios may be contributing to increases of OM in those regions. However, comparing the changes in seasonal precipitation to changes in $\text{PM}_{2.5}$ indicates that changes in aerosol scavenging of soluble aerosols are not strongly affecting average $\text{PM}_{2.5}$ concentrations in these simulations. In particular, precipitation decreases strongly in the central US during the winter under all three RCPs, but wintertime $\text{PM}_{2.5}$ concentrations decrease in that region under RCP4.5 and RCP8.5, and are largely unchanged under RCP6.0.

The increment in MDA8 O_3 per degree of warming projected during summer and autumn varies regionally (Fig. 13), but there is some consistency in spatial patterns between the RCPs. During summer under RCP4.5 and RCP8.5, $\Delta\text{O}_3 / \Delta T$ ranges from 0.5 to $1.0\ \text{ppb K}^{-1}$ over much of the Northern Rockies, Upper Midwest, Ohio Valley, and Northeast regions, and $0.5\text{--}1.0\ \text{ppb K}^{-1}$ in the South, Southeast, Ohio Valley, and Upper Midwest regions during autumn. The temperature change projected under RCP6.0 during autumn (Fig. 10) is near zero, which explains the extreme values for $\Delta\text{O}_3 / \Delta T$. By contrast, the proportionality between projected O_3 and daily maximum temperature is negative in much of the South and Southeast, particularly under RCP4.5 and RCP6.0. This negative relationship between daily maximum temperature and MDA8 O_3 is consistent with observation-based sensitivities reported for the Southeast during summer (Camalier et al., 2007; Porter et al., 2015).

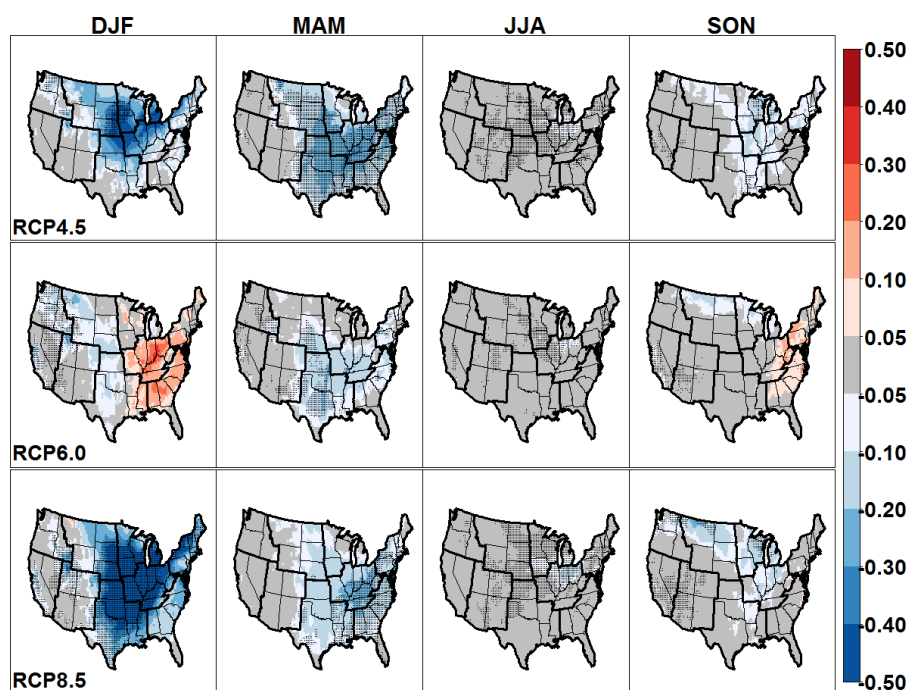


Figure 8. Changes in seasonal mean concentrations (μg m⁻³) of PM_{2.5} nitrate under three RCP scenarios. Dark pixels indicate where differences are significant according to Student's *t* test ($p < 0.05$).

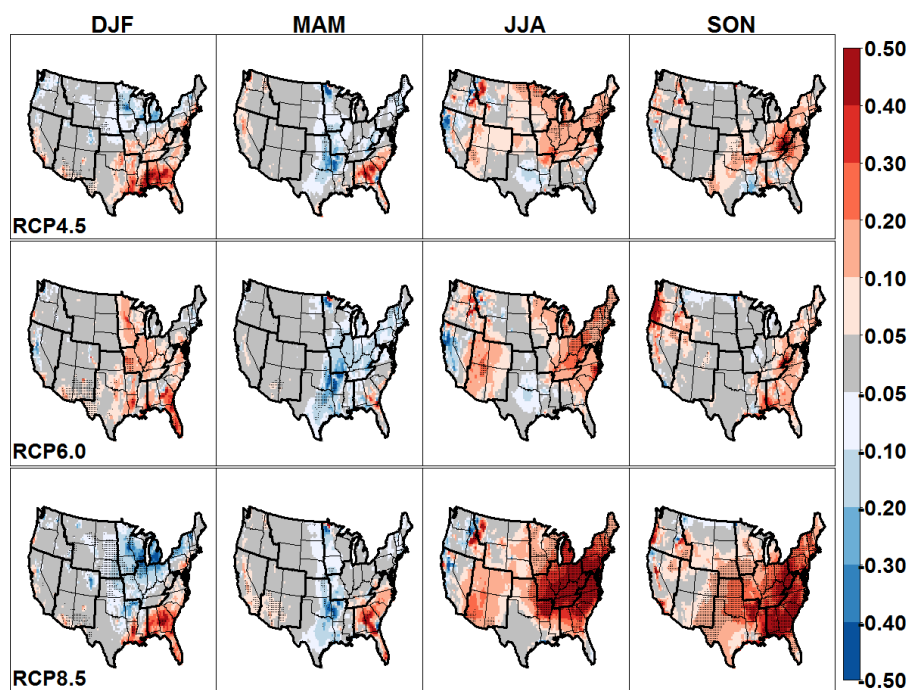


Figure 9. Changes in seasonal mean concentrations (μg m⁻³) of PM_{2.5} organic matter under three RCP scenarios. Dark pixels indicate where differences are significant according to Student's *t* test ($p < 0.05$).

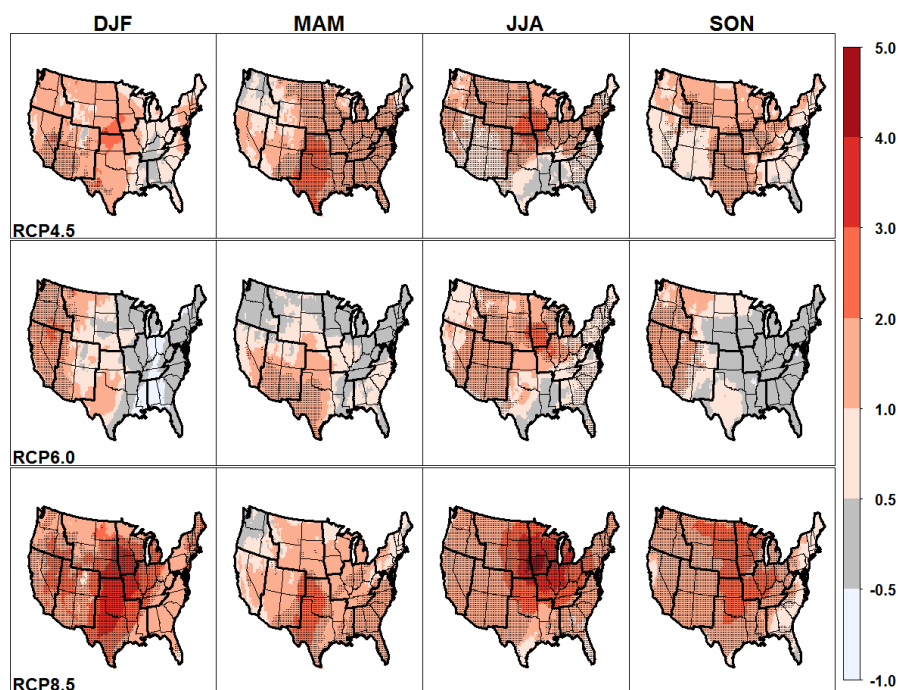


Figure 10. Projected changes in seasonal averages of daily maximum 2 m temperature (K) from 1995–2005 to 2025–2035 under RCP4.5, RCP6.0, and RCP8.5. Dark pixels indicate where differences are significant according to Student's *t* test ($p < 0.05$).

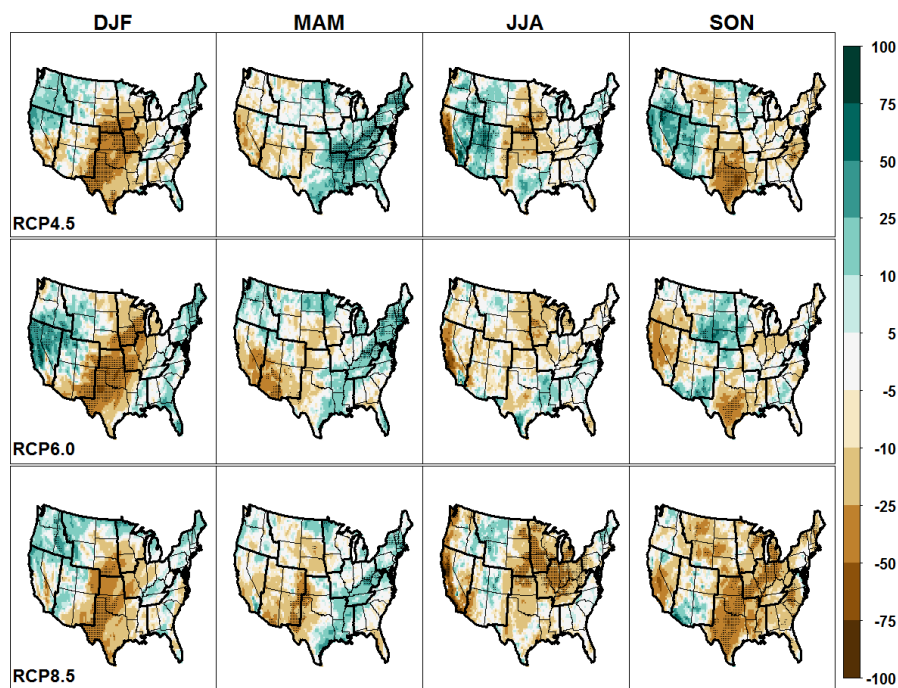


Figure 11. Relative changes projected in seasonal accumulated precipitation (%) from 1995–2005 to 2025–2035 under RCP4.5, RCP6.0, and RCP8.5. Dark pixels indicate where differences are significant according to Student's *t* test ($p < 0.05$).

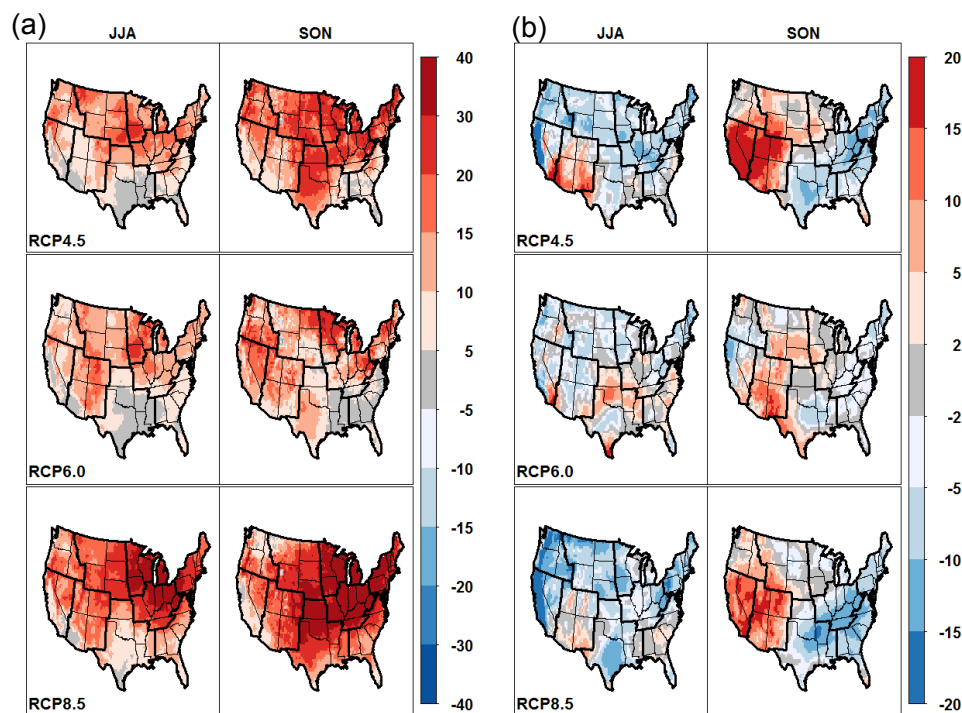


Figure 12. Projected changes (%) in summer and autumn averages of biogenic isoprene emissions (a) and cloud fraction (b) between 1995–2005 and 2025–2035 under RCP4.5, RCP6.0, and RCP8.5.

5 Conclusions

This study investigated the impacts of climate change on regional ozone and PM_{2.5} air quality across the conterminous US. Global CESM simulations were dynamically downscaled to 36 km horizontal grid spacing with WRF, and these meteorological fields were used by CMAQ to simulate air quality. The climate scenarios represent the year 2030 under RCP4.5, RCP6.0, and RCP8.5, and differences were analyzed relative to a historical period representing the year 2000. Comparison of simulated temperature and precipitation to reanalysis data showed that the CESM–WRF modeling system performed well for temperature, with absolute biases of less than 2 K for most regions of the US and most seasons of the year. WRF also showed reasonable skill at representing the variability in daily maximum and minimum temperatures throughout the conterminous US. Seasonal and annual precipitation biases in the central and eastern US were generally less than 25 %, but precipitation was positively biased in the western US throughout the year and in most of the eastern US during summer.

For the air quality simulations, anthropogenic emissions and boundary conditions were unchanged between the historical and future periods to isolate the meteorological effects of climate change on air quality from non-meteorological factors. Results indicated increases in seasonal mean MDA8 O₃ during summer in the Northern Rockies, Upper Mid-

west, Ohio Valley, and Northeast regions under all scenarios. The increase was largest under RCP8.5, exceeding 4 ppb in parts of the Northern Rockies and Upper Midwest regions. Smaller increases of up to 2 ppb were simulated during autumn, while changes during spring were generally less than 1 ppb. Increases were magnified at the upper end of the O₃ distribution in the Upper Midwest, Ohio Valley, Northeast, and Southeast regions. PM_{2.5} concentration changes varied by scenario and by season, with annual average changes of up to $\pm 1.0 \mu\text{g m}^{-3}$. Decreases in PM_{2.5} were principally due to reductions in aerosol NO₃⁻ during winter and spring, accompanied by lesser decreases in NH₄⁺ and SO₄²⁻, due to warmer temperatures causing increased gas-phase partitioning. Increases in secondary organic aerosol occurred during summer and autumn due to increased biogenic emissions.

Observational evidence (Bloomer et al., 2009) and modeling studies (Rasmussen et al., 2013) have argued that the O₃ climate penalty (ppb K⁻¹) is lower at reduced levels of NO_x emissions. It is important to recognize that the results presented here use a projected 2030 emission inventory with continued implementation of NO_x emissions controls. The increase in O₃ resulting from a given climate scenario would be expected to be greater if NO_x emissions are higher than projected here, particularly in NO_x-limited regions such as the eastern US.

The physical and chemical processes that influence air pollutant concentrations are complex, and there are numer-

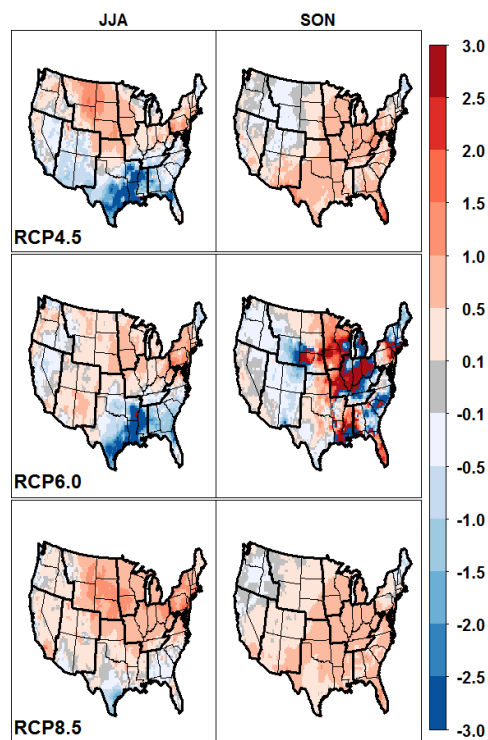


Figure 13. Ratio of projected changes in seasonal MDA8 O₃ to changes in seasonal daily maximum 2 m temperature (ppb K^{−1}) for summer and autumn between 1995–2005 and 2025–2035 under RCP4.5, RCP6.0, and RCP8.5.

ous aspects that may potentially vary due to climate change. Quantities examined to account for the modeled changes in pollution included temperature, precipitation, PBL height, wind speed, cloud cover, isoprene emissions, and the number of days with stagnant weather conditions. Temperature and isoprene emissions were found to have the greatest changes under all scenarios, especially in summer, and the greatest subsequent impact on O₃ and PM_{2.5} concentrations.

There are a number of important limitations of the present study. To isolate the effect of climate change on air quality, we kept anthropogenic emissions constant across all modeled years. However, electric sector emissions increase during peak temperature events due to increased demand for air conditioning, and emissions from electric generating units used to provide power during peak periods are less strictly regulated (Farkas et al., 2016). The increased emissions associated with increased electricity demand during heat waves is not represented in our analysis, potentially underestimating the impact on upper percentile and annual fourth-highest O₃ levels. Although biogenic emissions of VOCs were estimated using the downscaled meteorology, our modeling did not consider changes to prevalence and distribution of species of vegetation, or the potential leaf-scale inhibition of biogenic isoprene emissions due to elevated atmospheric CO₂ concentrations (Tai et al., 2013; Sharkey

and Monson, 2014). Other natural emissions sources potentially affected by climate change, including wildfires and windblown dust, were neglected in this work. We did not model changes in lightning NO_x formation rates or changes in stratosphere–troposphere exchange of O₃. We also did not consider changes in drivers of global baseline air pollution, including atmospheric methane levels, foreign emissions scenarios, and long-range transport to the US. Finally, there is substantial interannual variability in air quality due to year-to-year changes in meteorology. Though we conducted four sets of 11-year continuous simulations to account for interannual variability to the extent that our computational resources made practicable, 11-year simulations are insufficient to represent the full range of natural variability in the earth's climate system (Garcia-Menendez et al., 2017).

The effects of climate change on O₃ and PM_{2.5} obtained in this study are in the range of those reported in similar studies focused on air quality in 2050 (Fiore et al., 2015, and references therein). However, to our knowledge this study represents the most comprehensive analysis of the potential changes in US regional-scale air quality due to climate change conducted to date, in that it encompassed three future climate scenarios for periods exceeding a decade in duration and considered changes in both O₃ and PM_{2.5}. The significant and widespread increases in model-projected MDA8 O₃ associated with specific future climate scenarios, including in some densely populated areas, have potentially important implications for ongoing efforts to reduce exposure to ozone and protect human health.

Data availability. CMAQ model code is available via US EPA (2014a). Model output associated with this paper will be available via the EPA Environmental Dataset Gateway at <https://edg.epa.gov>.

Supplement. The supplement related to this article is available online at: <https://doi.org/10.5194/acp-18-15471-2018-supplement>.

Author contributions. CGN and TLS designed the study in consultation with JHB, MSM, and PDD. CGN conducted the analysis and wrote the paper. All authors helped shape the analysis and the content of the paper by commenting on prior versions.

Competing interests. The authors declare that they have no conflict of interest.

Disclaimer. The views expressed in this article are those of the authors and do not necessarily represent the views or policies of the US Environmental Protection Agency.

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EDF'S EXHIBIT DDD



The mechanisms and meteorological drivers of the summertime ozone–temperature relationship

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Abstract. Surface ozone (O_3) pollution levels are strongly correlated with daytime surface temperatures, especially in highly polluted regions. This correlation is nonlinear and occurs through a variety of temperature-dependent mechanisms related to O_3 precursor emissions, lifetimes, and reaction rates, making the reproduction of temperature sensitivities – and the projection of associated human health risks – a complex problem. Here we explore the summertime O_3 –temperature relationship in the United States and Europe using the chemical transport model GEOS-Chem. We remove the temperature dependence of several mechanisms most frequently cited as causes of the O_3 –temperature “climate penalty”, including PAN decomposition, soil NO_x emissions, biogenic volatile organic compound (VOC) emissions, and dry deposition. We quantify the contribution of each mechanism to the overall correlation between O_3 and temperature both individually and collectively. Through this analysis we find that the thermal decomposition of PAN can explain, on average, 20 % of the overall O_3 –temperature correlation in the United States. The effect is weaker in Europe, explaining 9 % of the overall O_3 –temperature relationship. The temperature dependence of biogenic emissions contributes 3 % and 9 % of the total O_3 –temperature correlation in the United States and Europe on average, while temperature-dependent deposition (6 % and 1 %) and soil NO_x emissions (10 % and 7 %) also contribute. Even considered collectively these mechanisms explain less than 46 % of the modeled O_3 –temperature correlation in the United States and 36 % in Europe. We use commonality analysis to demonstrate that covariance with other meteorological phenomena such as stagnancy and humidity can explain the bulk of the remainder of the O_3 –temperature correlation. Thus, we demonstrate that

the statistical correlation between O_3 and temperature alone may greatly overestimate the direct impacts of temperature on O_3 , with implications for the interpretation of policy-relevant metrics such as climate penalty.

1 Introduction

Tropospheric ozone (O_3) negatively influences human health, agricultural crop yields, and ecosystem integrity (Monks et al., 2015; World Health Organization, 2006; Tai et al., 2014; Fuhrer et al., 2016). As a secondary pollutant, O_3 is not directly emitted from natural or anthropogenic sources, but rather forms as a result of photochemistry in the presence of precursors including nitrogen oxides (NO_x), carbon monoxide (CO), and volatile organic compounds (VOCs). While the chemical processes leading to the formation of tropospheric O_3 are well understood, the sensitivity of O_3 production to changes in ambient conditions and precursor concentrations is complex and nonlinear. Local NO_x and VOC emissions are two of the most important contributors to daytime tropospheric O_3 production, but the ratio between the two can be as important as the overall emission magnitudes themselves (Sillman, 1999). NO_x /VOC emission ratios of roughly 1 : 8 produce the highest O_3 production rates in simplified box models (Sillman and He, 2002). Therefore, increases in precursor emissions might increase, maintain, or even reduce O_3 concentrations, depending on the initial NO_x /VOC ratio.

Further contributing to this complexity, O_3 formation and transport are highly sensitive to local meteorological conditions (Elminir, 2005). Precursor emissions and concentra-

tions themselves can depend on the weather, for example in the case of temperature-dependent emission of biogenic VOCs from vegetation (Guenther et al., 1995). As a product of photochemical reactions, tropospheric O₃ formation also requires sunlight, and can be sensitive to atmospheric stability, transport, and mixing conditions. Hot, sunny, stagnant conditions are often associated with the greatest risk of extreme O₃ events, as these days typically provide the ideal combination of precursor concentrations, photochemical reactions, and stable conditions for the pollutant to form and persist over an extended period of time (Jacob et al., 1993; Lin et al., 2001).

Because of this sensitivity to climate, increases in continental surface O₃ has been identified as a possible negative side effect of a warming climate, a relationship commonly referred to as the “ozone climate penalty”. First coined in 2008 by Wu et al., the climate penalty quantifies the additional ozone present in a warmer environment, as well as the additional anthropogenic emissions reductions necessary to compensate for this enhanced O₃ production. Given a 2–5 ppbv increase in O₃ expected with 2050 climate projections, Wu et al. (2008) concluded that an additional 10 % reduction in NO_x emissions would be necessary to mitigate these climate-driven ozone increases, above and beyond the ongoing reduction in NO_x emissions observed across much of the industrialized northern midlatitudes. This climate penalty is highly region-specific, depending on both current local conditions as well as the nature of future changes. In related work, Bloomer et al. (2009) defined the slope of the observed daily O₃–temperature correlation as the “climate penalty factor”, and found a decreasing trend in this factor over time as a result of NO_x emission reduction efforts.

While not synonymous, the long-term climate penalty defined by Wu et al. (2018) and the daily climate penalty factor calculated by Bloomer et al. (2009) can be understood to be driven by a similar set of temperature-dependent mechanisms. Previous work has examined this temperature–O₃ relationship and identified several mechanisms most likely to be responsible, in particular temperature-dependent biogenic VOC emissions and PAN dissociation rates (Jacob et al., 1993; Sillman and Samson, 1995; Jacob and Winner, 2009). Additionally, the temperature dependence of natural soil NO_x emissions (Yienger and Levy, 1995) and O₃ dry deposition (Wesely, 1989) have been recognized in previous studies, and could contribute to the overall O₃–temperature correlation. Each of these four mechanisms is included in typical chemical transport models (CTMs) used to study atmospheric chemistry, making these models useful tools for estimating the relative contributions of each mechanism to the overall O₃–temperature relationship.

2 Model description

To investigate the relative importance of each temperature-dependent mechanism in governing the overall O₃–temperature relationship we explore multiple regional sensitivity cases with the chemical transport model GEOS-Chem v9-02 (<http://www.geos-chem.org>, last access: 7 August 2018). GEOS-Chem is driven by assimilated meteorology from the NASA Global Modeling and Assimilation Office (GMAO); here we use the GEOS-5 product for 2010–2011. Our simulations over North America and Europe are performed at the native grid horizontal resolution of 0.5° × 0.667° with 47 vertical levels. Boundary conditions are provided from a global GEOS-Chem simulation at 2° × 2.5° horizontal resolution.

The default tropospheric chemical mechanism in GEOS-Chem v9-02 includes a description of NO_x–hydrocarbon–O₃–aerosol chemistry with over 120 species which participate in over 400 kinetic and photolytic reactions (Mao et al., 2013). To better capture the temperature dependence of O₃ formation as a result of biogenic emissions, we add monoterpene chemistry to the standard GEOS-Chem v9-02 gas-phase mechanism following Fisher et al. (2016), as in Porter et al. (2017). We use the EPA’s NEI2005 emissions inventory for anthropogenic emissions over the United States after scaling them up to match NEI2011 national totals for the years 2010 and 2011, then reducing NO_x emissions following the recommendations of Travis et al. (2016). European anthropogenic emissions are taken from EMEP inventories (Auvray and Bey, 2005). To represent global biomass burning we use the GFED3 inventory (Mu et al., 2011). NO_x emissions from lightning are treated using a modified parameterization first developed by Price and Rind (1992) and further constrained by satellite data (Murray et al., 2012). Soil NO_x emissions and biogenic hydrocarbon emissions are calculated online following the Hudman et al. (2012) and MEGAN2.1 (Guenther et al., 2012) schemes. Dry deposition is modeled using the Wesely “resistor in series” approach (1989). Wet removal includes contributions from scavenging in convective updrafts, in-cloud rainout, and below-cloud washout and is described by Amos et al. (2012).

GEOS-Chem has been shown to reproduce key spatiotemporal features of surface and column ozone observations, though biases and uncertainties are also known (Zhang et al., 2011; Hu et al., 2017). In particular, uncertainties in anthropogenic emission inventories (Travis et al., 2016), various drivers of biogenic emissions (Arneth et al., 2011; Vinken et al., 2014), and lightning NO_x (Murray, 2016) have been found to play important roles in the variability of tropospheric ozone and its precursors. Uncertainties in spatial inputs, including the datasets used to drive biogenic emissions such as plant functional type and leaf area index distributions, can also influence the resulting biogenic emissions and ozone impacts, and changes or updates to these inputs would influence the magnitude and distribution of the resulting tem-

perature sensitivities (Guenther et al., 2006; Arneth et al., 2011). Ongoing advances in the development of chemical mechanisms relevant to ozone formation and loss (Mao et al., 2013; Sherwen et al., 2016) have also underscored the importance of chemistry. While a full analysis of the sensitivity of the O_3 – T relationship to each of these factors is beyond the scope of this work, uncertainties in these and other modeled parameters and inputs can all influence both overall ozone production and the temperature sensitivities examined here.

2.1 Ozone–temperature mechanisms in the GEOS-Chem model

The temperature dependence of biogenic VOC emissions (especially those of isoprene) has been frequently cited as an important mechanism contributing to the observed O_3 –temperature correlation (Wu et al., 2008; Jacob and Winner, 2009; Doherty et al., 2013; Rasmussen et al., 2013), but the magnitude of this biogenic contribution to O_3 –temperature sensitivity remains uncertain. Additional VOC emissions on hot days would be expected to increase O_3 production in areas high in NO_x , but other areas – especially those with a particularly low NO_x /VOC ratio – might show constant or even reduced O_3 levels due to ozone quenching (Loreto and Velikova, 2001), leading to an inverse relationship. Biogenic emissions also do not necessarily vary linearly with temperature. Isoprene emissions, for example, are observed to plateau and eventually shut down completely at very high temperatures (Harley et al., 1999). Representative isoprene and monoterpene emissions response curves are shown in Fig. 1a, based on the GEOS-Chem implementation of MEGAN2.1. In the United States, isoprene and monoterpene emissions are highest in the southeast region, where high temperatures and foliage density provide ideal conditions in summer months (Fig. 2a and b). Europe is characterized by much lower emissions of isoprene overall, though monoterpene emitters are relatively common across the region (Fig. 2a and b).

While NO_x levels in the lower troposphere are dominated by anthropogenic sources throughout the year, natural processes can also play an important role (Zhang et al., 2003). Of the commonly recognized biogenic sources of NO_x , emissions of NO as a result of microbial activity in the soil have the clearest and most widely observed temperature relationship (Williams et al., 1992). Building upon the work of Hudman et al. (2012) and others, GEOS-Chem includes an exponential temperature-dependent factor for soil NO_x emissions, with plateaus at 30 °C (Fig. 1b), along with additional factors to account for vegetation type, soil moisture, fertilizer treatment, and canopy losses. This scheme has been shown to produce NO_2 levels in broad agreement with satellite observations in terms of spatial and temporal variability, though a systematic underprediction in model results suggests that modeled soil emissions may need to be further increased overall (Vinken et al., 2014). Modeled summer NO_x emis-

sions vary greatly by location, peaking in the American Midwest and southern European countries (Fig. 2c).

As a so-called NO_x reservoir species, PAN ($CH_3COO_2NO_2$) serves as an important means of nitrogen transport and is one of the primary chemical links between O_3 and daytime temperature. A product of reactions between non-methane VOCs and NO_x , PAN has an atmospheric lifetime that is typically longer than its ozone-producing precursors. However, due to the temperature dependence of its primary sink – thermal decomposition – this lifetime varies significantly based on meteorological conditions, with warmer temperatures favoring PAN decomposition and thus local NO_x production (Fig. 1c and Fischer et al., 2014). This temperature sensitivity has been identified as a dominant reason for the O_3 –temperature relationship in past measurement and modeling studies (Beine et al., 1997; Dawson et al., 2007; Jacob and Winner, 2009). PAN concentrations tend to correlate with NO_x emissions, and therefore modeled concentrations peak in the eastern United States as well as central Europe (Fig. 2d), where anthropogenic emissions are highest.

Depositional loss to vegetation and other surfaces is a key sink of O_3 and other pollutants. Traditional models of dry deposition processes use a “resistor-in-series” approach, in which barriers to O_3 deposition through various pathways are parameterized and represented as an electrical circuit (Wesely, 1989). This model has had some success in reproducing observed patterns of O_3 deposition velocities, though large uncertainties remain due to the scarcity of long-term measurements (Silva and Heald, 2018). In the Wesely resistance scheme, surface temperature influences deposition rates in two ways: through a stomatal resistance term that is very high at two extremes (typically freezing temperatures and around 40 °C) and reaches a minimum at some ideal temperature (Fig. 1d), and an exponentially decreasing nonstomatal term designed to reduce deposition over frozen (or nearly frozen) surfaces. In typical summer environments across the United States and Europe, only the stomatal term is relevant in practice, linking extremely high temperatures with increased stomatal resistance, thereby increasing local O_3 levels on very hot days. While observations of O_3 dry deposition velocities relative to meteorological drivers show mixed results (Clifton et al., 2017), in principle large-scale increases in stomatal resistance as a result of changes in temperature could lead to increases in O_3 concentrations. Summer O_3 deposition velocities across the United States and Europe as simulated by GEOS-Chem tend to range from 0.2 to 0.5 cm s^{−1}, depending on local surface type and climatology (Fig. 2e).

3 Methodology

To represent our control case we use a 2-year base scenario (BASE) for 2010–2011 in which temperature-dependent pro-

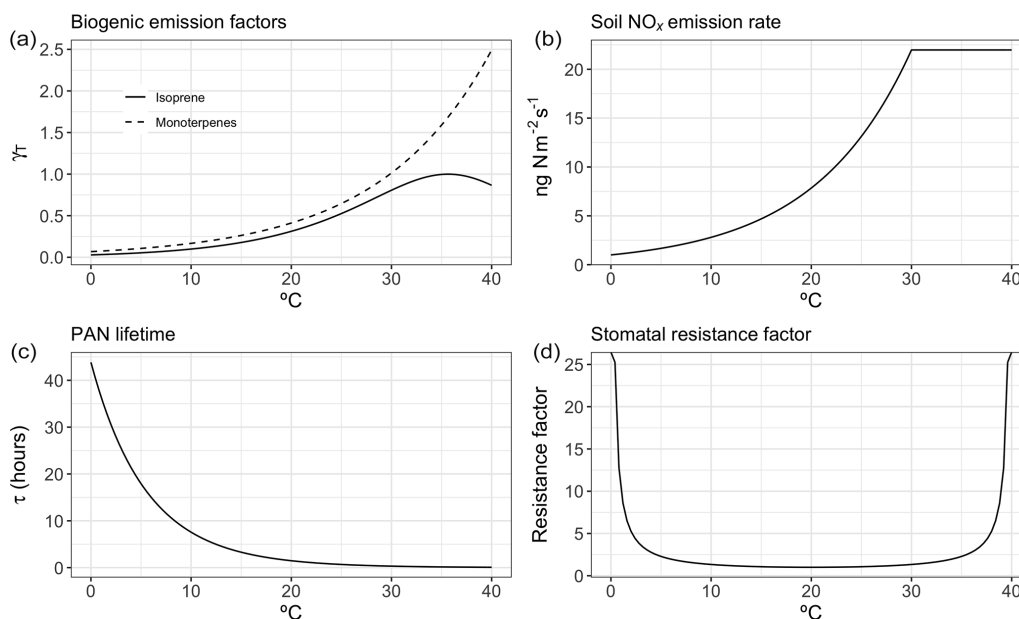


Figure 1. Representative temperature-dependent mechanism responses within GEOS-Chem for biogenic emissions (a), soil NO_x emissions (b), PAN lifetime (c), and stomatal resistance (d).

cesses within GEOS-Chem are unchanged. We then sequentially remove the temperature dependence from the four key O₃–*T* mechanisms discussed in Sect. 2.1 to explore the impact that each has on the overall O₃–*T* relationship over a 3-month summertime period (JJA), with an additional month for spinup (Table 1). Finally, we run nested regional simulations for each year over the United States and Europe, again discarding the first month of each run to focus on the three summer months (JJA). To isolate the impact of temperature dependence on biogenic emissions (BIO case), dry deposition (DEP case), and soil NO_x emissions (SOIL case), we generate a set of hourly temperatures representing the mean summer (JJA) value at each nested grid cell. To do so, we generate mean hourly temperatures for each modeled grid cell by averaging each hour (0 through 23) across the 3 modeled months. This averaged diurnal cycle is then substituted into each examined mechanism in turn, resulting in a repeating temperature profile being applied to calculations related to the modified mechanism. Through this procedure, diurnal patterns are preserved while day-to-day temperature variability for that mechanism is removed, preventing it from directly influencing the overall daily O₃–*T* correlation. In the PAN case, the default GEOS-Chem chemical mechanism is modified to remove temperature dependence from PAN dissociation by assuming a local constant temperature of 15 °C everywhere for that particular reaction.

To confirm that our four chosen mechanisms (biogenic VOC emissions, soil NO_x emissions, PAN dissociation, and dry deposition) are in fact collectively responsible for most of the direct connection between temperature and O₃ within GEOS-Chem, we perform an additional set of sensitivity

tests over each of our regional domains. In one modified case we uniformly increase all temperatures by 1 °C, resulting in widespread increases in average surface O₃ levels (Fig. 3a). In a second modified case we again increase temperature by 1 °C, but decouple temperature from the four chosen mechanisms using original mean hourly temperatures as described above. In the decoupled case, surface O₃ shows negligible differences in mean surface O₃ (Fig. 3b and c), indicating that the four decoupled mechanisms dominate the directly modeled O₃–*T* relationship, with the residual O₃ changes likely resulting from temperature-dependent chemical kinetics for species other than PAN.

For observational comparison, we use data from the EPA's Air Quality System (AQS) network of monitoring sites (US Environmental Protection Agency, 2016), as well as the AirBase air quality database maintained by the European Environment Agency (EEA).

4 Results and discussion

The simulated O₃–temperature relationship in GEOS-Chem for the two modeled summers, as represented by the slope of a gridded O₃–*T* ordinary least-squares (OLS) regression, is fairly consistent with AQS and AirBase observations, lending confidence to the use of modeled sensitivity comparisons to examine the significance of underlying mechanisms (Fig. 4a). In both the United States and Europe, spatial patterns and overall mean values of the O₃–*T* correlation are fairly well represented, though the full range of sensitivities is not reproduced in the model output (root-

Table 1. Summary of GEOS-Chem cases.

Case	Modifications from default GEOS-Chem
BASE	Reduced United States NO _x , added monoterpene chemistry
BIO	BASE, plus normalized temperature for biogenic VOC emissions
SOIL	BASE, plus normalized temperature for soil NO _x emissions
DEP	BASE, plus normalized temperature for dry deposition
PAN	BASE, plus removed temperature dependence for PAN thermal decomposition
ALL	BASE, plus all changes from BIO, SOIL, DEP, and PAN cases

mean-square error of 0.84 and 0.79, mean bias of 0.02 and -0.13 ppbv O₃ °C⁻¹ for the United States and Europe respectively). In spite of the relatively strong agreement between modeled and observed O₃–*T* correlations, we highlight a number of shortcomings in the modeled representation of this relationship which may explain the remaining discrepancies between the model and observations. For one, the anthropogenic emission inventories used in GEOS-Chem are independent of daily temperatures, while in reality there are connections between meteorological variability and emissions from human activities such as transportation and energy production. In addition, the grid cell size in GEOS-Chem is incapable of capturing the full diversity of subgrid meteorological phenomena, many of which may be important at the surface station level. Local temperature and O₃ fluctuations may vary significantly from those of the gridded average. These issues, among others, may contribute to some of the differences seen in the comparison between observed and modeled sensitivities. In particular, the magnitude of both high and low extremes tends to be underestimated in gridded output from GEOS-Chem, resulting in a tighter distribution of modeled output and skewed slope of modeled vs. observed values, especially in Europe (Fig. 4c). However, in spite of the notable differences between modeled and observed O₃–*T* relationships at the tails of the distributions, a relatively small overall bias is apparent across station types in both urban and remote regions (Fig. 4b). Here, the more remote stations associated with the National Park Service (NPS) are separated from the rest of the AQS dataset for comparison over the United States, while AirBase stations in Europe are split by station area category (urban/suburban and rural). In each category, nearest-neighbor grid cells effectively capture the center of the observed distribution, even though extremes are not fully represented, particularly at rural European stations.

Given that the mean values and spatial distribution of regional O₃–*T* sensitivities are generally consistent with observations, we analyze the mechanisms contributing to modeled sensitivities by decoupling them from temperature variability individually and simultaneously. Removing temperature dependence from the four chosen mechanisms has noticeable impacts on correlations between temperature and O₃ in the simulated cases, with regional differences apparent in each

case. For each of the four cases examined, the strength of the O₃–temperature dependence (measured via the coefficient of determination *R*²) was examined through linear regression and compared to that seen in the BASE case. When subtracted from the BASE values, the resulting difference in *R*² can be understood as the contribution of that particular mechanism to the overall modeled sensitivity (Fig. 5).

Temperature-dependent biogenic VOC emissions have a positive impact on O₃–temperature correlation through most of the United States, especially around urban centers, but have a negative impact across much of the southeast. This is consistent with expectations based on NO_x/VOC ratios (Fig. 2f), in which NO_x-rich regions experience a boost in O₃ production when rising temperatures lead to additional VOC emissions. Much of the southeast region of the United States, however, is already saturated in VOCs (primarily isoprene), and thus additional emissions on hot days reduce O₃ production efficiency, or even act as an O₃ sink. The heavily forested northern regions of Europe are likewise less influenced (or even negatively influenced) by the temperature dependence of biogenic emissions, while the high-NO_x regions of central and southern Europe show strong positive contributions. Changes in *R*² reach up to 0.14 and 0.21 in the United States and Europe, respectively, representing on average 3 % and 9 % of the overall regional O₃–*T* correlation (Fig. 5).

The impact of temperature dependence in dry deposition is distributed roughly congruently with leaf area index (LAI) coverage across the United States, contributing up to 0.14 to the O₃–*T* *R*² but only 0.02 on average. Little effect is seen in the heavily forested regions of Northern California and the Pacific Northwest, but since deposition is a removal effect and O₃ levels are relatively low in those regions to begin with, changes in deposition rates could be expected to have minimal impact on the overall O₃–temperature relationship there. Relative contributions of deposition on a local basis, however, can represent over one-quarter of the overall O₃–*T* correlation in some US locations. The overall impact of temperature-dependent dry deposition is even less pronounced in Europe, reaching up to 0.08, but averaging less than 0.01 across the region.

Temperature-dependent soil NO_x emissions contribute around 0.04 to the coefficient of determination in both re-

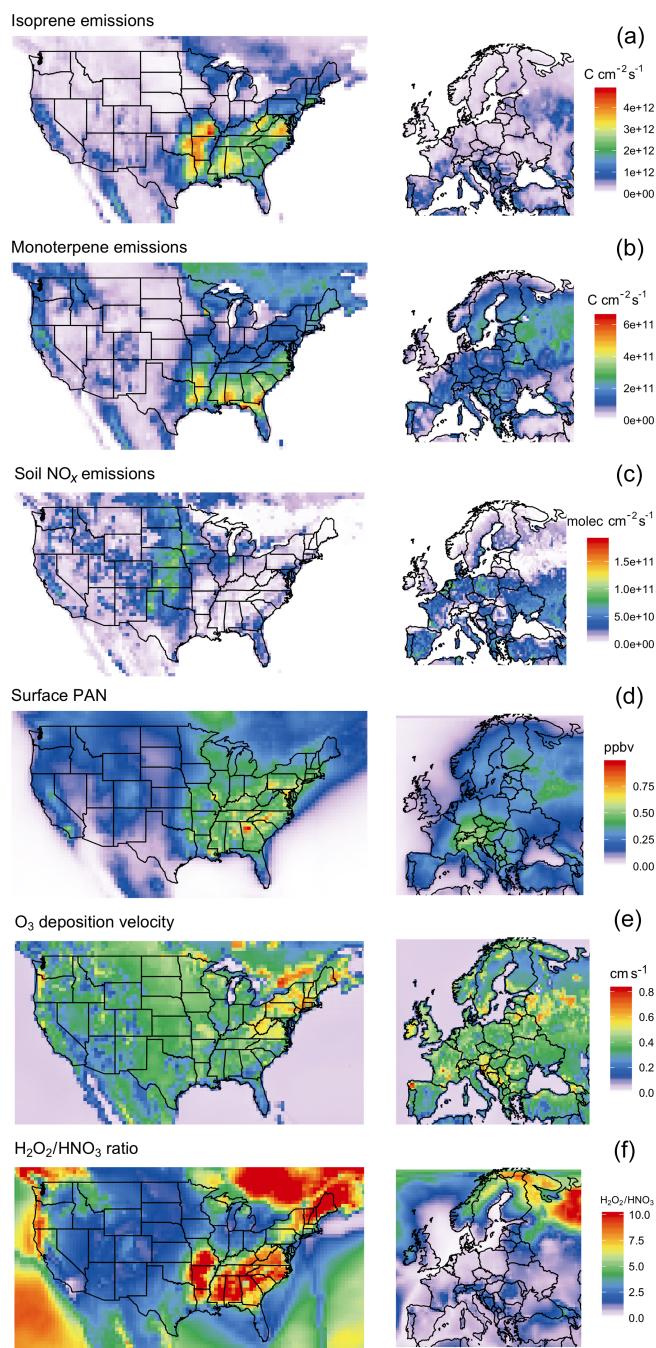


Figure 2. Summer mean values (JJA 2010–2011) for modeled isoprene and monoterpene emissions (a, b), soil NO_x emissions (c), surface PAN mixing ratios (d), O_3 deposition velocity (e), and NO_x/VOC sensitivity as represented by the surface $\text{H}_2\text{O}_2/\text{HNO}_3$ ratio (f).

gions, representing 10 % of the total R^2 value in the United States and 7 % in Europe. Notably, the impact of temperature dependence in soil emissions does not match up directly with the overall magnitude of those emissions themselves (Fig. 2c), indicating that this fluctuation represents a

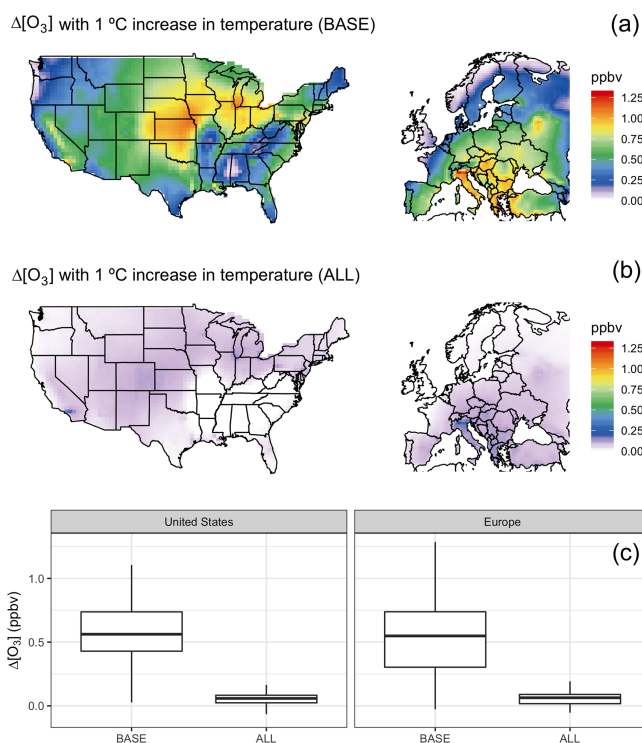


Figure 3. Increase in O_3 with a 1 °C increase in temperature in the BASE case (a) and with fixed temperature mechanisms in the ALL case (b). Distribution of changes for each shown in boxplots (c).

relatively minor and diffuse effect. Areas characterized by lower NO_x/VOC ratios due in part to low NO_x emissions (Fig. 2f) are also more likely to exhibit stronger sensitivity to temperature-driven soil NO_x variability.

The temperature dependence of PAN decomposition is a strong contributor to the O_3 –temperature relationship in both the United States and Europe, particularly in the American Midwest, where the positive impact of this mechanism reaches 0.32. Impacts are also visible across most of the eastern United States, as well as the Southern California and Central Valley regions, and the O_3 – T R^2 increases by 0.07 on average in the US (almost 20 % of the total mean). PAN temperature sensitivity is also a strong contributor to the O_3 – T relationship in Europe by up to 0.14 (9 % of total mean R^2). Of the examined model mechanisms in the United States, PAN lifetime is the strongest overall contributor to the correlation between O_3 and temperature, though it places a close second to biogenic emissions in Europe.

While each modeled mechanism contributes to the overall O_3 – T relationship in the United States and Europe, none of them come close to completely explaining the BASE case correlation between O_3 and T . Even when all temperature-dependent mechanisms are removed from the model (the ALL case), most regions still show O_3 –temperature sensitivities of 50 % or more of their original BASE values as measured by R^2 . While there are uncertainties associated

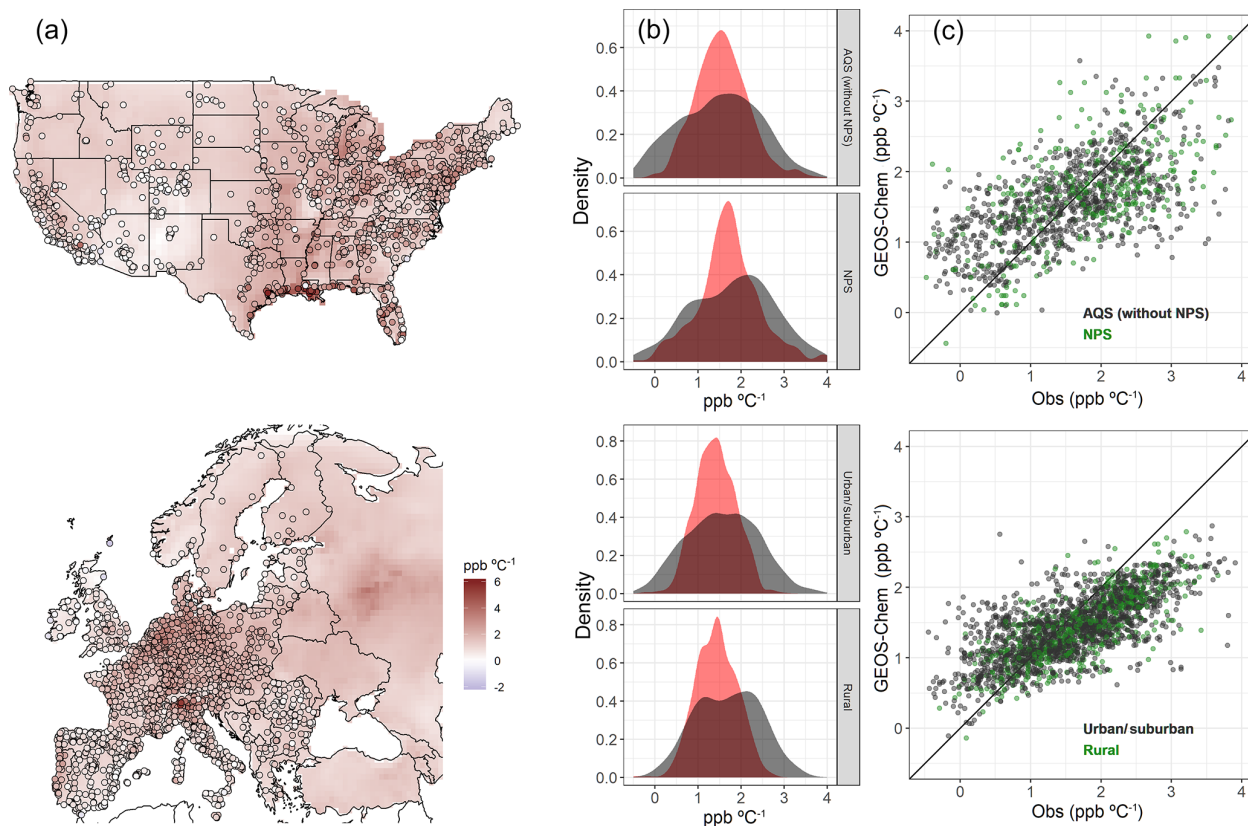


Figure 4. Regression slopes of summer (JJA) daily maximum 8 h average O₃ vs. daily maximum temperature for GEOS-Chem and station observations in the United States and Europe. Station data points are overlaid on gridded model output in panel (a). Distributions for observed (black) and modeled (red) O₃–*T* slopes are shown in panel (b), further separated by station category: US stations are separated between the more remote NPS stations and the remaining stations of the AQS network, while European stations are split by AirBase area category into urban/suburban and rural station types. Scatterplots in panel (c) show modeled values vs. observed, with green points used to mark NPS stations in the US and rural area stations in Europe. The remaining AQS stations, as well as those AirBase stations categorized as urban or suburban, are shown as black points.

with comparing statistical sensitivities across these simulated cases, it seems clear that the O₃–temperature relationship cannot be fully (or even mostly) explained by these four mechanisms within GEOS-Chem (Fig. 5).

Beyond the directly temperature-dependent emission and loss mechanisms examined within GEOS-Chem, many other meteorological effects can influence surface O₃ levels, and correlations between these phenomena and temperature could show up as part of the observed O₃–temperature correlation. For example, strong winds can act as a removal mechanism for locally produced O₃. If strong winds are also correlated to cooler temperatures, this would show up as a positive correlation between O₃ and temperature, despite the lack of any explicit temperature-dependent mechanism. While decoupling other meteorological processes from temperature in the manner demonstrated above can be highly problematic, even within a model, statistical methodologies such as commonality analysis allow for some degree of attribution of observed predictive power between temperature and the other meteorological drivers (Seibold and McPhee, 1979). Derived

from the analysis of linear regression output, commonality analysis involves the calculation of *R*² values for all possible permutations of predictor variables included in the analysis. These *R*² values are then compared, allowing for the calculation of explained variability that is uniquely provided by one variable or another, along with explained variability that is shared between two or more of the covariates. For the purposes of this study, “unique” refers to that portion of a variable’s correlation with the response variable (ozone) that is not shared with any other predictor, while “shared” refers to the portion of the correlation that could be attributed to multiple predictors. A more detailed explanation of the equations involved, as well as examples of their application, can be found in Seibold and McPhee (1979).

To quantify the contributions of meteorological variables to the modeled O₃–temperature correlation, we apply commonality analysis to all gridded output. Through this methodology we are able to decompose all gridded surface O₃–temperature *R*² values into unique and shared contributions among each of the five variables examined, which are sum-

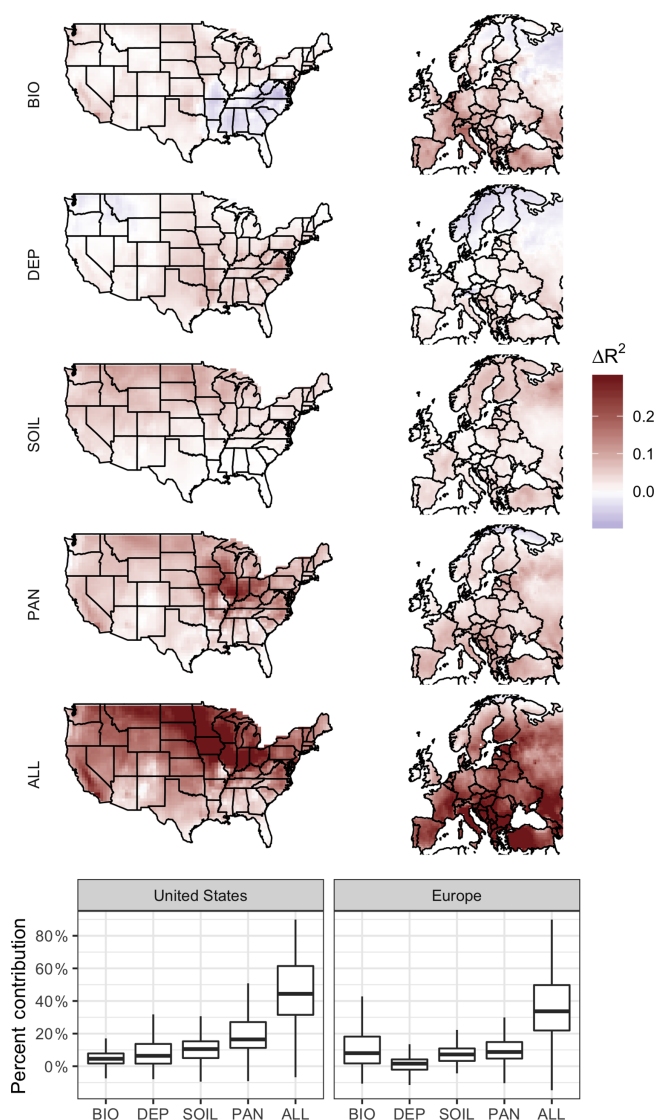


Figure 5. Impact of temperature dependence of biogenic emissions, O_3 dry deposition, soil NO_x emissions, PAN lifetime, and all mechanisms at once. Plotted values show the difference between O_3 –temperature correlation in the BASE case and that of the modified case in which dependence on daily temperature variability is removed.

marized in Table 2: maximum daily temperature (T), humidity (HUM, represented by dew point temperature), mean wind speed (WSPD), wind direction (WDIR), change in mean surface pressure (ΔP), and planetary boundary layer (PBL) height. The unique correlations for each of these variables are shown in Fig. 6, along with the portion of their correlation shared with any other variables (in the case of T) or shared with daily maximum temperature (in the case of the other five meteorological variables).

Each unique component represents the portion of explained variability that could be explained solely by one meteorological variable among the six, meaning that the R^2

Table 2. Meteorological variables examined.

Variable	Description
T	Maximum daily temperature
HUM	Mean daily vapor pressure (humidity)
WDIR	Normalized U and V wind vectors
WSPD	Mean daily wind speed
ΔP	Change in daily mean surface pressure
PBL	Maximum daily planetary boundary layer height

value would be expected to drop by that amount if the predictor were removed from the linear fitting equation. Shared components can be understood as overlap between predictor variable contributions, meaning that the actual mechanism responsible for the correlation might reasonably be attributed to any of the involved predictors. While this methodology is imperfect, especially given the assumption that not all relevant meteorological processes are represented by these six predictors, it does provide additional insight into how and where the O_3 –temperature correlation might be at least partially explained by correlation with other meteorological phenomena.

As shown, temperature has the strongest and most widespread unique correlation with O_3 variability of any of the six meteorological variables included in both the United States and Europe. However, even this strong unique contribution is significantly less than the magnitude of the shared component, meaning that collectively the remaining five predictors could potentially explain the majority of the predictive power that temperature offers alone. The overall predictive power for each meteorological variable, along with the respective shared and unique components, can be further visualized through their mean values across all grid cells. Figure 7 shows region-averaged attribution of shared and unique correlation through stacked columns: each individual column height shows the total correlation (in the form of R^2) between ozone and a single meteorological variable, while individually shaded sections differentiate unique and shared components. In each meteorological column that particular variable's unique contribution is at the bottom, and shared contributions are grouped where possible into clusters of two or three total variables for clarity. To best represent the unique contribution of temperature, commonality analysis presented here is performed on the ALL case, with all four chosen temperature-dependent mechanisms decoupled. The difference in total correlation between ALL and BASE cases (which are driven by identical meteorology) is then added into the unique temperature contribution, as this gap can be fully attributed to temperature dependence. Therefore, performing commonality analysis on the BASE case alone would underpredict the unique temperature contribution since some percentage of variability driven specifically by temperature-dependent mechanisms could also correlate

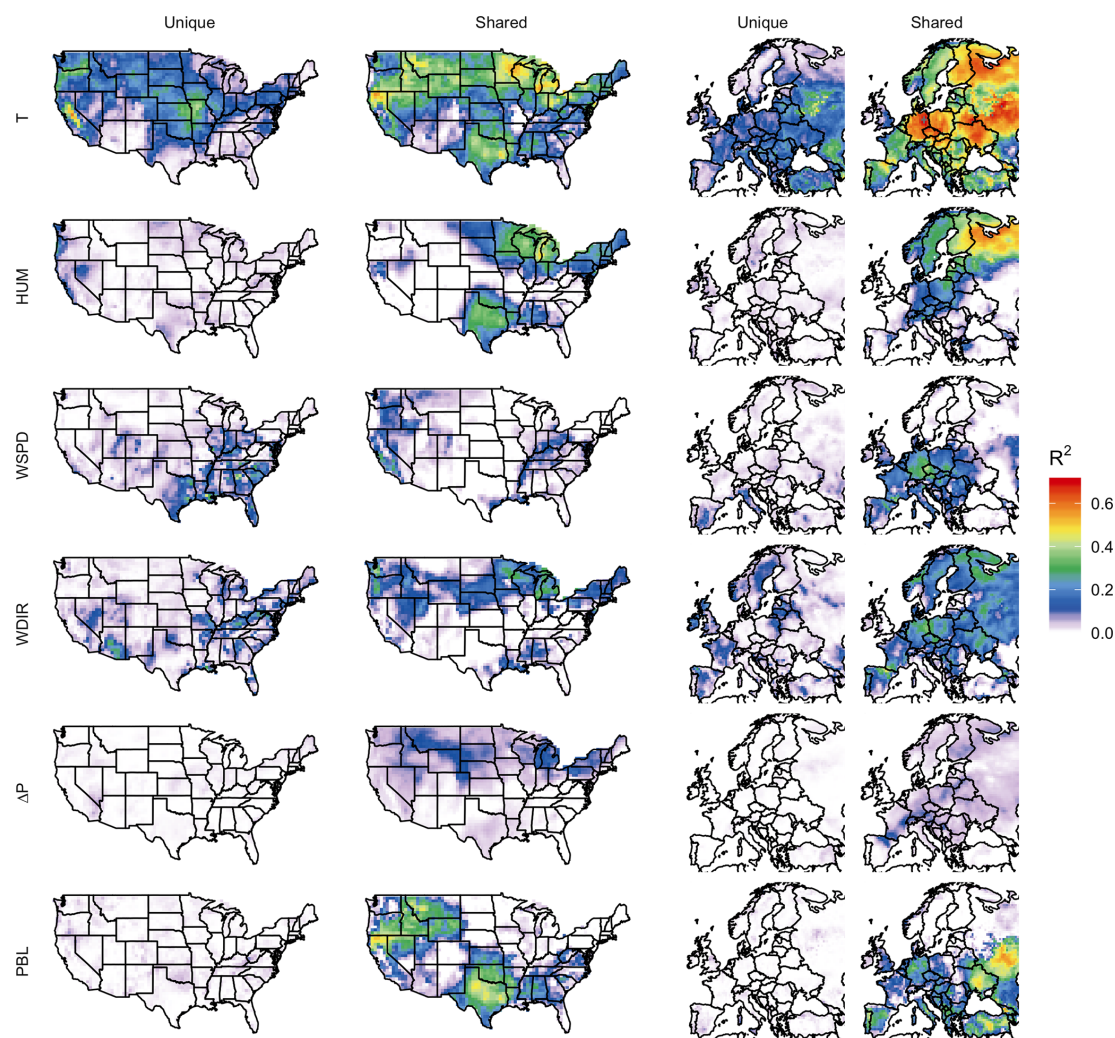


Figure 6. Unique and shared O_3 correlation among meteorological variables in the BASE case. Unique contributions represent predictive power provided by one meteorological covariate alone, while shared correlation could be attributed to one or more other covariates.

with other meteorological variables. Combining commonality analysis along with the results of the BASE-ALL comparison makes full use of the attribution information contained in each since any lost correlation with temperature-dependent mechanisms turned off can be attributed directly to temperature alone, better constraining the commonality analysis itself. Through this analysis it is apparent that over half of the O_3 –temperature relationship in the United States and Europe (shown by the leftmost bar in each panel) can be explained through correlation with one or more meteorological covariates, especially wind direction, humidity, and planetary boundary layer height. Europe shows an even stronger overall correlation between temperature and O_3 , and much of that increase appears to be related to a stronger influence from wind and humidity.

We note that these unique and shared designations are heavily dependent on predictor variable choice and would certainly vary when calculated using a different set of me-

teorological predictor variables. Uniqueness in these figures should, therefore, be taken as an upper limit estimate, as the inclusion of additional meteorological covariates could demonstrate commonality with temperature where this six-variable set does not. Furthermore, commonality shared between meteorological variables does not imply causation by any one of the members – it only indicates shared statistical predictive power and the possibility of alternative O_3 -producing mechanisms. However, there are a number of possible mechanisms that could explain some of the predictive power demonstrated by non-temperature variables. Wind speed and direction have perhaps the most straightforward meteorological relationship to O_3 , and they represent transport of the pollutant either to or away from its source location. Wind speed is generally inversely correlated to high temperatures, and stable conditions are also favorable for the buildup and retention of high O_3 concentrations. Depending on local topography and pressure patterns, wind direction can

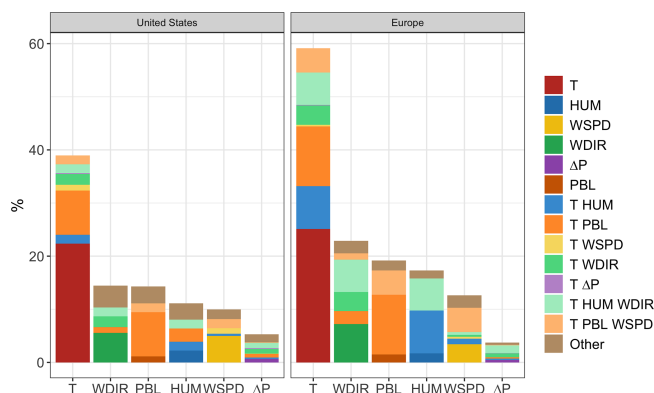
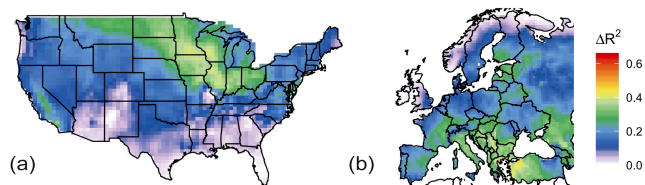


Figure 7. Unique and shared contributions to O_3 correlation for each of six different meteorological variables in the BASE case. Column heights represent overall predictive power for each variable, while individual colors indicate predictive power unique to that variable (bottom color in each column) or shared by one or more other meteorological variables.

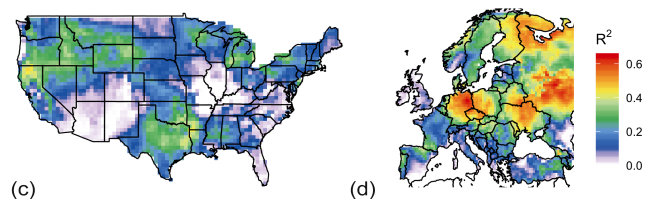
also correlate strongly with changes in temperature, shifting the final destination of polluted air masses from one location to another. Previous work described a relatively small role for these advective mechanisms (Camalier et al., 2007), but the results here suggest that, after temperature-specific mechanisms have been accounted for, wind speed and direction together account for a larger fraction of explained O_3 variance than previously suggested. Humidity can influence O_3 formation in a number of ways, both directly and indirectly. Water vapor itself participates in competing O_3 -related effects: water molecules act as O_3 sinks by reacting with $O(^1D)$ atoms to produce OH, preventing the excited oxygen from regenerating O_3 . However, in polluted conditions the OH can then act as an O_3 precursor itself, potentially increasing production through reactions with CO and VOCs. These competing effects may explain the relatively weak unique contribution of humidity on average, though the high shared fraction (especially in Europe) suggests that other indirect impacts may be involved, such as correlation with cloud cover or fog. Mixing depth has shown mixed results as a predictor for ozone in past studies as well (Jacob and Winner, 2009), as the impact of PBL variability depends strongly on location and local conditions. Areas with low surface O_3 can show positive correlations with mixing layer height due to the entrainment of higher concentrations from aloft, while polluted regimes can show strongly negative correlations due to the higher concentrations of trapped precursors on low-PBL days.

Although the specific mechanisms through which the non-temperature meteorological variables impact O_3 are not identified through this statistical methodology, it is apparent that the majority of modeled O_3 –temperature correlation left unexplained with the decoupling of temperature-dependent mechanisms (T – O_3 R^2 in the ALL case, Fig. 5)

Increased correlation from all mechanisms (BASE-ALL)



Shared meteorological correlation (ALL)



Average contribution to O_3/T correlation

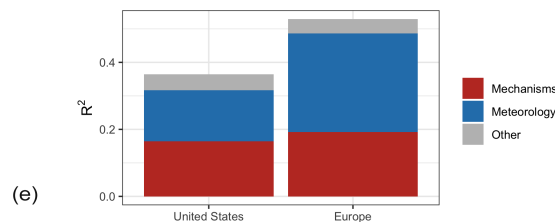


Figure 8. Total contribution of modeled mechanisms to the O_3 –temperature correlation in GEOS-Chem (a, b), possible contribution of the other included meteorological variables (c, d), and mean value for each category by region as a fraction of the total O_3 –temperature correlation (e, f).

can itself be explained in principle through covariance with other meteorological variables, indicating that this covariance could explain the residual correlation left over when temperature-dependent mechanisms are turned off within GEOS-Chem. While the difference in O_3 – T correlation between the BASE and ALL cases shows that these temperature-dependent mechanisms do indeed strongly influence the O_3 –temperature correlation across a large portion of the northern United States and southern Europe (Fig. 8a, b), the remaining correlation makes up the larger overall fraction. Shared explanatory power, as indicated by the shared contribution of temperature in the ALL case (Fig. 8c, d), indicates that covariance with one or more additional meteorological variables could explain most of the remaining O_3 – T correlation (Fig. 8e). In this panel, red areas of each column represent the fraction of BASE O_3 – T correlation that is lost through the decoupling of temperature-dependent mechanisms, blue areas show the shared fraction of remaining temperature dependence in the ALL case, and the gray region represents remaining O_3 variability that is uniquely explained by temperature but unaffected by the four described mechanisms. This remaining correlation could be the result of imperfectly chosen meteorological variables, residual temperature dependence within the model from chemistry or

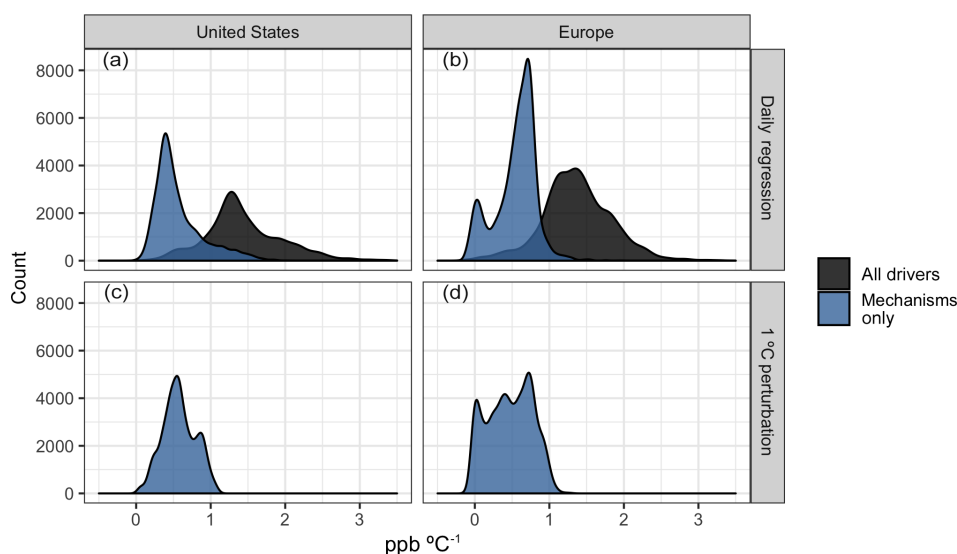


Figure 9. Distribution of O_3 – T sensitivities as measured by the slope of OLS regression (above) and mean surface O_3 differences from a flat 1°C temperature perturbation (below). Regression values are shown for all modeled drivers (BASE case, black) and the portion of those slopes attributable to temperature-dependent mechanisms (BASE – ALL, blue).

other mechanisms, or other fluctuations in emissions or other inputs that happen to covary with temperature.

While day-to-day O_3 –temperature variability is a useful and commonly examined metric for estimating future changes in air quality under a warming climate, it presents challenges with respect to the extrapolation of daily variability into long-term trends. For example, areas that exhibit little day-to-day variability in summer temperature over the study period may appear to be insensitive to climate change, even though the low O_3 –temperature correlation is simply a result of short-term climatological stability. The temperature perturbation cases described previously and shown in Fig. 3a provide some additional information on how the daily sensitivities examined here compare to larger, long-term shifts. Figure 9a, b show the distribution of O_3 – T sensitivities, both as a whole (black fill) and considering only the four key mechanisms previously examined (blue fill). These distributions can then be compared to the distribution of O_3 changes apparent with a simple temperature perturbation (panels c and d), which intrinsically includes no other meteorological covariance. While the day-to-day correlation between O_3 and temperature from all modeled drivers (Fig. 9a, b, black fill) predicts increases in O_3 of around 1.4 ppb for a 1°C increase in temperature, roughly half of that is attributable to the examined mechanisms alone. This portion attributed to mechanisms alone is consistent with the mean change in O_3 observed from a 1°C increase in temperature (0.58 ppb in the US and 0.47 ppb in Europe). Together, the consistency of these two outcomes indicates that projections of O_3 concentrations under future climate scenarios will be dependent on an accurate representation of temperature-dependent meteorology and dynamics and that models relying on temperature-

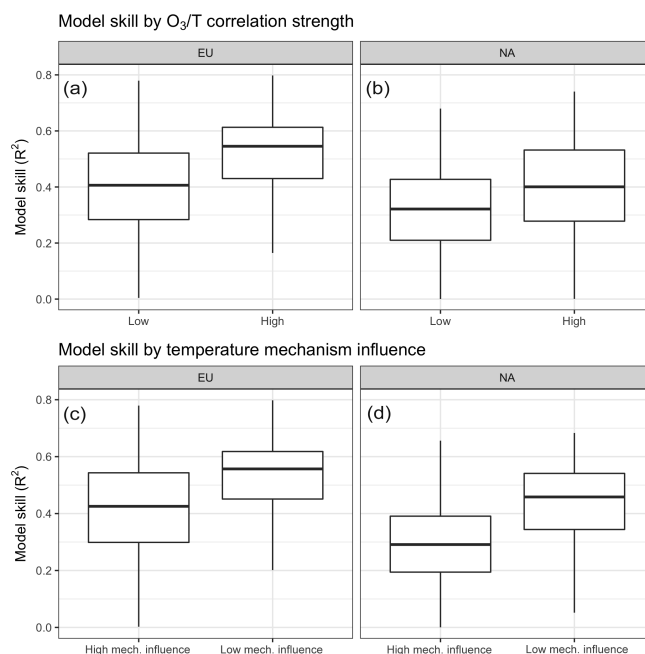


Figure 10. Differences in model skill compared to surface station observations as a function of overall O_3 –temperature correlation (a, b) and the relative importance of modeled temperature-dependent mechanisms (c, d).

dependent emissions and chemical mechanisms alone may underpredict the strength of O_3 – T sensitivities by over 60 %.

Model behavior can be further analyzed through comparison to surface station observations, which reveals a significant difference ($P < 0.001$) in model skill (as measured by

modeled vs. observed daily mean O_3) when grouping stations by overall O_3 – T correlation as well as by the relative importance of modeled mechanisms (Fig. 10). Matching observations from the EPA's AQS network in the United States and the EEA's AirBase dataset for Europe with nearest-neighbor grid cells from GEOS-Chem output shows that model skill tends to be higher in regions characterized with above-average O_3 –temperature correlation (BASE case O_3 –temperature $R^2 > 0.42$). While this does not imply that temperature-dependent processes are all modeled correctly, it does at least suggest that temperature-based drivers tend to be better captured by the model than other influences on O_3 variability. However, splitting observed stations based on the relative importance of internally modeled mechanisms shows that more work may need to be done on these implementations. Grid cells in which the modeled O_3 –temperature relationship was dominated by temperature-dependent mechanisms (greater than 50 % of the O_3 –temperature correlation lost when temperature dependence was removed in the ALL case) showed much less overall predictive power when compared to the corresponding surface observations (Fig. 10c, d).

5 Conclusions

A changing climate implies changes in the physical and chemical regimes governing the emission, formation, and transport of pollutants such as tropospheric O_3 . Previous work has identified increasing temperatures in particular as a driver of elevated surface O_3 concentrations, mitigating the effectiveness of ongoing emissions reductions in the United States and Europe. This means that, under a warming climate, polluted regions would need to cut emissions even further to achieve the same improvement in air quality, adding economic and human health costs to the bottom line of climate change adaptation. Understanding the mechanisms driving the observed relationship between O_3 and temperature is important for guiding improvements in model performance, as well as for better understanding the effects of future changes.

We show here that while temperature-dependent mechanisms such as biogenic emissions and PAN dissociation are often cited as key contributors to the observed O_3 –temperature relationship, model simulations maintain strong O_3 –temperature correlations even when these mechanisms are completely decoupled from temperature variability. Analysis of other meteorological variables suggests that meteorological covariance with temperature may explain a large proportion of O_3 –temperature correlation – over 40 % in the United States and nearly 60 % in Europe. The relative importance of covarying atmospheric dynamics indicates that simulations investigating temperature perturbations alone will underestimate overall O_3 impacts by a factor of 2 or more, unless temperature-driven changes in other meteorological patterns are also included and accurately represented. Fur-

thermore, comparison with station observations shows that modeled daily O_3 values are less skillful in areas where the O_3 –temperature correlation is dominated by modeled temperature-dependent mechanisms rather than meteorology, indicating that improved representation of these mechanisms in particular may improve overall model skill with respect to O_3 modeling and forecasting.

These results highlight the complexity of pollution projections under changing emissions and climatological conditions, as well as with the attribution of those changes to any individual driver or metric. While surface temperatures can be easily linked to O_3 variability statistically, it is apparent that the robustness of this relationship depends on how consistently coupled those temperature changes continue to be, not only with temperature-dependent physical and chemical drivers of O_3 formation, but also with the covarying meteorological patterns that appear to be just as influential. These relationships are further confounded by ongoing changes in anthropogenic emissions, making it especially important to understand the ways in which policy-driven emissions reductions may improve – or fail to improve – air quality within a changing climate. Ongoing investigations into the importance of these mechanisms, emissions, and atmospheric dynamics will guide future model development, improving forecast skill and better informing policy decision-making.

Data availability. GEOS-Chem code is available at <http://acmg.seas.harvard.edu/geos/> (last access: 1 March 2018). Data from the EPA's AQS network of surface air quality observations are available at <https://www.epa.gov/aqs> (last access: 9 August 2016), while AirBase data maintained by the EEA are available at <https://www.eea.europa.eu/data-and-maps/data/airbase-the-european-air-quality-database-7> (last access: 31 July 2015).

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Competing interests. The authors declare that they have no conflict of interest.

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EDF'S EXHIBIT EEE

REBUTTAL TESTIMONY OF MAUREEN LACKNER

I. QUALIFICATIONS

I, Maureen Lackner, am an Economics and Policy Manager in the Office of the Chief Economist at Environmental Defense Fund (“EDF”). I earned a Master of Public Policy from the Gerald R. Ford School of Public Policy, University of Michigan in 2017. For the past four years I have provided analysis on climate and environmental issues with a special focus on methane emissions from the oil and gas sector. My work on this issue includes economic analyses on proposed regulations and policy design, as well as modeling to track global policy ambitions and abatement opportunities. My resume is attached as EDF Ex. FFF.

II. DOCUMENTS REVIEWED

In preparing my rebuttal, I reviewed the following documents:

- Testimony of John Dunham, NMOGA App’x A6.
- Memorandum prepared by John Dunham, Managing Partner, to New Mexico Oil & Gas Association, Estimated Costs of Proposed Ozone Precursor Rule on Oil and Natural Gas (June 13, 2021), NMOGA Statement of Intent to Present Technical Testimony, NMOGA App’x A6.
- EDF, New Mexico Oil & Gas Data, Methane and Air Toxics website.
- Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (Feb. 2021), EDF Ex. GGG.
- Marcy Lowe and Robin Lowe-Skillern, Find Measure Fix: Jobs in the U.S. Methane Emissions Mitigation Industry, Datu Research (2021), EDF Ex. III.

- Carleton, Tamma and Greenstone, Michael, Updating the United States Government's Social Cost of Carbon (January 14, 2021). University of Chicago, Becker Friedman Institute for Economics Working Paper No. 2021-04, EDF Ex. HHH.
- The Western Oil and Natural Gas Industry, 2018 Economic Impact Study, John Dunham & Associates, NMOGA Ex. 36.
- Well methodology, NMOGA Ex. 37.

III. THE ADDITIONAL OPERATIONAL COSTS DO NOT ACCURATELY REFLECT THE REGULATIONS.

The Memorandum prepared by John Dunham, Managing Partner, to New Mexico Oil & Gas Association (“JDA analysis”) makes several assumptions that lead to an overestimate of the additional operational costs imposed by the rules. First, the analysis assumes that close to 82,000 wells will be impacted by the rules. In contrast, EDF estimates the NMED proposal would require only 49,615 wells to install controls. Our estimate is based on the 54,000 active wells with production in 2019. In addition to limiting our count to active wells, the lower number reflects that not all counties are covered by the rule and that 4,522 wells within these impacted counties would be exempt from many of the control requirements in the rules pursuant to the small business exemption. Assuming the added administrative and operational costs per oil and gas well listed in the JDA analysis are correct, decreasing the number of oil and gas wells covered by the rules results in an adjusted cost to the industry of \$1.8 billion in the first year. This is 43% lower than the figure reported in the JDA analysis. Even this estimate may be incorrect as the cost data are not documented—for example, the equipment costs are based on undisclosed survey results from just 10 companies.

A second assumption that we believe incorrectly increases the overall cost is that operators will invest in every requirement under the rule within the first year. This is not the case, as several components of the rule allow for delayed compliance. Specifically, the NMED proposal allows operators up to seven years (until January 1, 2029) to phase in control requirements for existing natural gas-fired spark-ignition engines; two years from the effective date of the rule to phase in requirements for existing compressors; 2 years from the effective date of the rule to control existing glycol dehydrators; 1 year to control existing heaters; 1 year to phase in requirements for new and existing hydrocarbon liquid transfers; 3 years to control existing pneumatic pumps; 3 years to control existing storage tanks with a potential to emit (PTE) between 2 and 10 tons per year (tpy) of volatile organic compounds (VOCs); 1 year to control existing storage tanks with a PTE greater than 10 tpy of VOCs; and a phase-in over 8 years to retrofit existing pneumatic controllers. Operators have the flexibility to optimize how they invest over a period of years.

Finally, the analysis does not factor in the additional revenue producers could realize from captured gas. EDF estimates that New Mexico producers waste about \$300 million worth of natural gas per year (based on assumption of \$4 Mcf of natural gas and that natural gas is 80% methane).¹ Investment in equipment that reduces these emissions could result in meaningful savings to industry.

IV. THE COSTS OF THE OIL AND NATURAL GAS INDUSTRY ARE OMITTED

The JDA analysis also omits social costs imposed by the industry. Social costs include climate damages from carbon dioxide (CO₂) emissions when oil and gas is combusted (estimated at a minimum of \$51 per metric ton), and climate damages from methane (CH₄) emissions that occur throughout the supply chain (estimated at a minimum of \$1,500 per metric ton). EDF Ex.

¹ EDF, New Mexico Oil & Gas Data, <https://www.edf.org/nm-oil-gas/emissions/>.

GGG. Using this conservative estimate of CH₄ damages, the social cost from CH₄ emissions related to New Mexico's oil and gas production amounts to roughly \$1.6 billion, EDF Ex. HHH.²

The analysis also omits costs to the people of New Mexico who would be exposed to unhealthy air. The analysis should account for local environmental damages incurred in New Mexico through degraded air quality and related health impacts associated with VOC emissions. EDF estimates these damages at 337,500 metric tons for 2019.³

V. THE REPORT DOES NOT ACKNOWLEDGE THE LIMITATIONS OF INPUT-OUTPUT MODELS.

This report estimates the indirect and induced economic impacts of the rule based on a model developed for Western Energy Alliance by JDA. The study does not adequately explain assumptions or test the strength of these assumptions in any kind of sensitivity analysis.

One assumption that appears to be in place is that the rule will not create jobs. This is likely incorrect. Research prepared by Datu Research on behalf of EDF finds that the methane mitigation industry is a young, but fast-growing source of high-quality jobs across the country. EDF Ex. III. These companies anticipate hiring more employees if additional methane regulations are put in place at the state or federal level.

² Carleton, Tamma and Greenstone, Michael, Updating the United States Government's Social Cost of Carbon (January 14, 2021). Univ. of Chicago, Becker Friedman Inst. for Economics Working Paper No. 2021-04, Available at SSRN: <https://ssrn.com/abstract=3764255> or <http://dx.doi.org/10.2139/ssrn.3764255>. Experts agree that the social cost of greenhouse gases should be revised up. For example, Carleton and Greenstone estimate an SCC of \$125 per metric ton by adjusting IWG SCC values for inflation and using a 2% discount rate.

³ EDF, New Mexico Oil & Gas Data, <https://www.edf.org/nm-oil-gas/emissions/>

EDF'S EXHIBIT FFF

Maureen Lackner

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Education

University of Michigan, Gerald R. Ford School of Public Policy, Ann Arbor, MI May 2017

Master of Public Policy

Columbia University, New York, NY May 2013

Bachelor of Arts, Political Science and Statistics

Experience

Environmental Defense Fund, New York, NY June 2017-Present

Economics and Policy Manager in the Office of the Chief Economist

- Design and manage a global oil and gas methane tracker in R that relies on best available data and a Monte Carlo analysis to simulate ranges of emissions and potential reductions; executive team members use the tool to track progress on methane reductions and to inform engagement strategies
- Research market-based policies to address issues such as methane abatement in the oil and gas sector, economywide emissions in the United States, and scaling new technologies
- Provide economic analyses to understand the viability of specific policy proposals; these analyses support EDF's direct engagement with policymakers at the national and state level

U.S. Government Accountability Office, Washington, D.C. May 2016-July 2016

Applied Research and Methods Intern

- Conducted research and stakeholder interviews regarding U.S. preparedness for Zika outbreak; presented findings to internal executives to inform development of audit plan and contributed to published blog post
- Contributed to written and visual analyses and prepared descriptive data analysis that will be used in an audit of the Department of Defense pertaining to pathogens in high-containment labs

Dow Sustainability Fellows Program, Ann Arbor, MI January 2016-December 2016

Dow Sustainability Masters Fellow

- Conducted focus groups for residents living in HOPE Village, an initiative of the non-profit Focus: HOPE
- Engaged with stakeholders from auto-industry, city government, and non-profit sector to inform analysis
- Used focus group results, GIS and census data to contribute to needs assessment and constraints analysis regarding potential for shared use mobility

The Commonwealth Fund, New York, NY October 2013-July 2015

Grants Associate

- Developed business intelligence solutions, including a real-time budget tool used across program areas
- Coordinated development of budgets, subcontracts, and data use agreements for quarterly grant approvals

Publications and Presentations

- Early deployment of direct air capture with dedicated geologic storage: Federal Policy Options. EDF Report. (2021). [With S. Capanna and J. Higdon]
- Pricing Methane Emissions from Oil and Gas Production. Environmental Defense Fund Economics Discussion Paper Series, EDF EDP 21-04. (2021) [With J. R. Camuzeaux, S. Kerr, and K. Mohlin]
- What do we know about methane emissions from the global oil and gas sector? 25th EAERE Annual Conference. (2020) Virtual Session. Policy Session Conference Presentation.
- Reverse Auctions: Lessons learned from renewables and storage procurement. 24th EAERE Annual Conference. (2019) The University of Manchester, Manchester, UK. Policy Session Conference Presentation.
- Policy Brief—Using Lessons from Reverse Auctions for Renewables to Deliver Energy Storage Capacity: Guidance for Policymakers. *Review of Envir. Econ. and Policy*. (2019) [With J. R. Camuzeaux and S. Koller]

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- Instruments of Political Control: National Oil Companies, Oil Prices, and Petroleum Subsidies. *Comparative Political Studies*. (2014) [With J. Urpelainen and A. Cheon]
- Why Do Governments Subsidize Gasoline Consumption? An Empirical Analysis of Global Gasoline Prices, 2002-2009. *Energy Policy*. Volume 56. (2013) [With J. Urpelainen and A. Cheon]

Programming and Software Skills

Excel, R, Stata, LaTeX, ArcGIS