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STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION
20.2.50 **No. EIB 21-27 (R)**
Oil and Gas Sector – Ozone Precursor Pollutants

STATEMENT OF INTENT TO PRESENT TECHNICAL TESTIMONY

The New Mexico Oil and Gas Association ("NMOGA"), pursuant to 20.1.2.206 NMAC and the Scheduling Order, submits this Statement of Intent to Present Technical Testimony for the Environmental Improvement Board's September 20, 2021 hearing on this matter.

1. **The name of the person for whom witnesses will testify.**

   The witnesses identified will testify on behalf of NMOGA.

2. **Name of each witness.**

   The names of NMOGA's technical witnesses are John Smitherman, Adam Meyer, Justin Lisowski, Dennis McNally, Ken Nichols, and John Dunham. NMOGA reserves the right to identify additional rebuttal witnesses.

John Smitherman
Senior Advisor - Petroleum Engineer
New Mexico Oil & Gas Association
123 W Booth St
Santa Fe, NM 87505
JRS@nmoga.org

Adam Meyer
Principal / VP of US Operations
Valor EPC
425 1 St SW
Calgary, AB T2P 3L8, Canada
adam.meyer@valorepc.com

Justin Lisowski
Project Manager / Rotating Equipment Engineer
Valor EPC
425 1 St SW

Calgary, AB T2P 3L8, Canada
justin.lisowski@valorepc.com

Dennis McNally
Senior Scientist
Alpine Geophysics, LLC
7341 Poppy Way, Arvada, CO 80007
dem@alpinegeophysics.com

Ken Nichols
National Practice Leader for Geologic Carbon Sequestration
8911 N. Capital of Texas Highway, Suite 2310
Austin, TX 78759
ken.nichols@tetratech.com

John Dunham
Managing Partner
Dunham & Associates
32 Court Street, Suite 207
Brooklyn, NY 11201
jrd@guerrillaeconomics.com

3. A copy of direct testimony

Direct testimony for each witness is provided in Appendix A.

- John Smitherman – Appendix A1
- Adam Meyer – Appendix A2
- Justin Lisowski – Appendix A3
- Dennis McNally – Appendix A4
- Ken Nichols – Appendix A5
- John Dunham – Appendix A6

4. Qualifications of witnesses

The qualifications of each witness are detailed in Exhibits 29-34.

5. Text of any recommended modifications to the proposed regulatory change.

A redline with additional supporting rationale is provided in Appendix B.

6. Exhibits anticipated to be offered at the hearing.

NMOGA anticipates the following exhibits may be offered at the hearing:

Exhibit #	Description	Prepared By

NMOGA 1	New Mexico Ozone Attainment Initiative Photochemical Modeling Study – Draft Final Air Quality Technical Support Document	Ramboll
NMOGA 2	Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5 and Regional Haze	EPA
NMOGA 3	Control Techniques Guidelines for the Oil and Natural Gas Industry	EPA
NMOGA 4	Cost per Ton for NSPS for stationary compression ignition (CI) internal combustion engine	Tanya Parise, Alpha-Gamma Technologies, Inc.
NMOGA 5	Equipment leak detection and quantification at 67 oil and gas sites in the Western United States	API
NMOGA 6	Characterizing Light-Off Behavior and Species-Resolved Conversion Efficiencies During In-Situ Diesel Oxidation Catalyst Degreening.	Knafl, A, S. Busch, M. Han, et al.
NMOGA 7	Supplementary Information Volume 3 for the CSU/DOE Gathering and Boosting Study	CSU/DOE
NMOGA 8	Changes in coal sector led to less SO2 and NOx emissions from electric power industry	EIA
NMOGA 9	MIRATECH Selective Catalyst Reduction System	Miratech
NMOGA 10	Table W-1A to Subpart W of Part 98, 40 CFR Part 98	EPA
NMOGA 11	Greenhouse Gas Emissions Reporting From the Petroleum and Natural Gas Industry, Background Technical Support Document	EPA
NMOGA 12	Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry. Table 5-15	API
NMOGA 13	Emissions from the Natural Gas Industry, Volume 12: Pneumatic Devices, Final Report	Shires, T.M. and M.R. Harrison. Methane
NMOGA 14	Equipment leak detection and quantification at 67 oil and gas sites in the Western United States, Supplemental Material	API
NMOGA 15	Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers	Allen, D. T.; Pacsi, A.; Sullivan, D.; Zavala-Araiza, D.; Harrison, M.; Keen, K.; Fraser, M.; Hill, A. D.; Sawyer, R. F.; Seinfeld, J. H.

NMOGA 16	Assessment of Uinta Basin Oil and Natural Gas Well Pad Pneumatic Controller Emissions. J. Environ. Prot. 8:394. 2017	Thomas, E. D., P. Deshmukh, R. Logan, M. Stovern, C. Dresser, and H. L. Brantley
NMOGA 17	UDAQ response to EPA Comments on Changing the Intermittent Pneumatic Controller Emission Factor for the Utah Air Agencies 2014 Emissions Inventory	UDAQ
NMOGA 18	First-in-the-nation rule to slash methane emissions from Colorado oil and gas operations relied on compromise	Mark Jaffe, the Colorado Sun
NMOGA 19	Oil and Natural Gas Sector Pneumatic Devices	U.S. EPA Office of Air Quality Planning and Standards
NMOGA 20	Convert Gas Pneumatic Controls To Instrument Air	EPA
NMOGA 21	2011 and 2017 Oil and Gas Emissions Inventory Development	Colorado Department of Public Health & Environment
NMOGA 22	[RESERVED]	
NMOGA 23	[RESERVED]	
NMOGA 24	API comments on the 2016 Control Techniques Guidelines	API
NMOGA 25	API comments on NSPS OOOOa reconsideration	API
NMOGA 26	API comments on NSPS OOOOa	API
NMOGA 27	Envirofacts Table for the Greenhouse Gas Reporting	EPA
NMOGA 28	CSU/DOE Gathering and Boosting study final report	CSU/DOE
NMOGA 29	John Smitherman Qualifications	John Smitherman
NMOGA 30	Adam Meyer Qualifications	Adam Meyer
NMOGA 31	Justin Lisowski Qualifications	Justin Lisowski
NMOGA 32	Dennis McNally Qualifications	Dennis McNally
NMOGA 33	Ken Nichols Qualifications	Ken Nichols
NMOGA 34	John Dunham Qualifications	John Dunham
NMOGA 35	May 2020 OEWS Estimates	Bureau of Labor Statistics, Department of Labor
NMOGA 36	The Western Oil and Natural Gas Industry 2018 Economic Impact Study	John Dunham
NMOGA 37	Well Methodology	John Dunham
NMOGA 38	Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector	EPA

NMOGA 39	New Mexico Crude Oil First Purchase Price	U.S. Energy Information Administration
NMOGA 40	FRED Graph Observations	Federal Reserve Bank of St. Louis

Respectfully submitted,

JORDEN HISER & JOY, PLC

By: /s/ Eric L. Hiser

Eric L. Hiser
Brandon Curtis
5080 N. 40th St, Suite 245
Phoenix, AZ 85024
(480) 505-3900
ehiser@jhjlawyers.com
bcurtis@jhjlawyers.com

GALLAGHER & KENNEDY, P.A.

By: /s/ Dalva L. Moellenberg

Dalva L. Moellenberg
1239 Paseo de Peralta
Santa Fe, New Mexico 87501-2758
505-982-9523
DLM@gknet.com

CERTIFICATE OF SERVICE

I hereby certify that on July 28, 2021, a true and correct copy of the foregoing ***Notice of Intent to Submit Technical Testimony*** was served via electronic mail to the following:

Pamela Jones
Hearing Administrator
Environmental Improvement Board
1190 Saint Francis Drive, Suite S2102
Santa Fe, New Mexico 87505
Pamela.jones@state.nm.us
Administrator for the Environmental Improvement Board

Karla Soloria
New Mexico Office of the Attorney General
P.O. Box 1508
Santa Fe, New Mexico 87504
ksoloria@nmag.gov
Counsel for the Environmental Improvement Board

Lara Katz, Assistant General Counsel
Office of General Counsel
New Mexico Environment Department
1190 St. Francis Drive
Santa Fe, New Mexico 87505
lara.katz@state.nm.us
Counsel for the New Mexico Environmental Department

Elizabeth deLone Paranhos
Delone Law Inc.
1555 Jennine Place
Boulder, Colorado 80304
elizabeth@delonelaw.com
Counsel for Environmental Defense Fund

J. Scott Janoe
Baker Botts LLP
910 Louisiana Street
Houston, Texas 77002
Scott.janoe@bakerbotts.com
Counsel for Oxy USA Inc.

Ana Maria Gutiérrez
Hogan Lovells US LLP
1601 Wewatta Street, Suite 900
Denver, CO 80202
Ana.gutierrez@hoganlovells.com

Sandra Milena McCarthy
Hogan Lovells LLP

Tannis Fox
Western Environmental Law Center
409 East Palace Avenue, #2
Santa Fe, New Mexico 87501
fox@westernlaw.org

David R. Baake
Baake Law LLC
2131 North Main Street
Las Cruces, New Mexico 88001
david@baakelaw.com
Counsel for Conservation Voters New Mexico, Diné C.A.R.E., Earthworks, Natural Resources Defense Council, San Juan Citizens Alliance, Sierra Club, and 350 New Mexico

Christopher J. Neumann
Gregory R. Tan
Casey Shpall
Greennberg Traurig, LLP
1144 Fifteenth Street, Suite 3300
Denver, CO 80202
neumannc@gtlaw.com
tangr@gtlaw.com
shpallc@gtlaw.com
Counsel for NGL Energy Partners LP, Solaris Water Midstream, Owl Swd Operating LLC, and Goodnight Midstream, LLC

Matthias L. Sayer

Columbia Square
555 Thirteenth Street, NW
Washington, DC 20004
Sandra.mccarthy@hoganlovells.com

Counsel for Kinder Morgan, Inc., El Paso Natural Gas Company, L.L.C., TransColorado Gas Transmission Co., LLC, and Natural Gas Pipeline Company of America, LLC

Charles de Saillan
New Mexico Environmental Law Center
1405 Luisa Street, Suite 5
Santa Fe, New Mexico 87505
cdesaillan@nmelc.org
Legal Counsel for New Mexico Environmental Law Center

Jeffrey Holmstead
Tim Wilkins
Whit Swift
Bracewell LLP
111 Congress Avenue, Suite 2300
Austin, Texas 78701
Jeff.holmstead@bracewell.com
Tim.wilkins@bracewell.com
Whit.swift@bracewell.com

Stuart R. Butzier
Christina C. Sheehan
Modrall, Sperling, Roehl, Harris & Sisk, PA
PO Box 2168
Albuquerque, New Mexico 87103-2162
srb@modrall.com
ccs@modrall.com
Legal Counsel for The Gas Compressor Association

NGL Energy Partners LP
125 Lincoln Ave, Suite 222
Santa Fe, NM 87501
Matthias.sayer@nglep.com
Legal Counsel for NGL Energy Partners, LP

Louis W. Rose
Kari Olson
Ricardo S. Gonzales
Montgomery & Andrews, PA
P.O. Box 2307
Santa Fe, NM 87504
lrose@montand.com
kolson@montand.com
rgonzales@montand.com
Legal Counsel for Independent Petroleum Association of New Mexico

Daniel Jaynes
Keifer Johnson
Gabriel Pacyniak
Natural Resources & Environmental Law Clinic, University of New Mexico
1117 Stanford Dr NE
Albuquerque, New Mexico 87106
jaynesda@law.unm.edu
johnsoke@law.unm.edu
pacyniak@law.unm.edu
Legal Counsel for Center for Civic Policy and NAVA Education Project

/s/ Eric L. Hiser
Eric L. Hiser

Appendix A1 – Direct Testimony of John Smitherman

STATE OF NEW MEXICO
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Oil and Gas Sector – Ozone Precursor Pollutants

TESTIMONY OF JOHN SMITHERMAN

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. John R. Smitherman, My official work address is 123 Booth St., Santa Fe, NM, 87505.

Q. WHAT IS YOUR INVOLVEMENT IN THIS PROCEEDING?

A. I represent the New Mexico Oil and Gas Association in their role as a party to these proceedings.

Q. WHAT IS YOUR OCCUPATION?

A. I am Senior Advisor to NMOGA.

Q. HOW LONG HAVE YOU HELD YOUR CURRENT POSITION?

A. Since February, 2020.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Petroleum Engineering from the University of Texas at Austin in 1980.

Q. PLEASE BRIEFLY SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. I worked for the same oil and gas exploration and production company from 1981 until I retired in 2020. I started as an entry-level production engineer in the Gulf Coast division office learning how to apply engineering and economic analysis to operational problems.

I then worked as a staff/reservoir engineer in the Fort Worth headquarters, mostly supporting our geologists and doing special projects for executive management. Next was a senior production engineering role, again in the Gulf Coast division with responsibilities for specific producing fields. It was during these years that personal computers began to be available and were introduced into our offices.

My first management position was Division Drilling and Production Superintendent for the West Texas division which oversaw the company's massive acreage position in southeast New Mexico. In this role I was deeply involved in all production functions and field operations, including operating cost control and budgeting, field personnel management, and operational data management.

Next was Division Engineer where I managed a staff of production and reservoir engineers and non-technical support staff who performed technical and economic evaluations, reservoir and reserve studies, and so forth.

In 1994 I was named Division Production Manager with responsibilities for all aspects of the West Texas division's office including engineering, drilling, field accounting, field operations, support staff, operations information management, and more.

In 2005 I was elevated to Vice President – Operations with responsibility over all division offices plus procurement (mostly tubulars), operations information, and eventually Environmental, Safety and Health (E,H,&S). I also interfaced with accounting, personnel/human resources, risk management, security, and legal departments.

Q. YOU MENTIONED DATA MANAGEMENT SEVERAL TIMES. COULD YOU EXPLAIN IN MORE DETAIL YOUR INVOLVMENT WITH THAT ASPECT OF THE BUSINESS?

A. My career spanned the period of time where personal computers and intracompany networks were developed. I was the first engineer with a PC on my desk in the company and I was involved with many of the developments of data management that transformed businesses across many sectors, including oil and gas. I was part of a team of engineers and other professionals who in the late 1980's created the first production database structure for the company comprised of multiple related tables of information and was also involved in the development and selection of many programs (applications in today's vernacular) that made engineers and non-engineers more productive. I am pleased to say that the database structure we created remained useful for over 30 years.

Q. HOW WERE YOU PERSONALLY INVOLVED WITH PROGRAM (APPLICATION) DEVELOPMENT?

A. Besides working with others on the production database structure, I wrote an application using a DataBase Management System (DBMS) program in the late 1980's to help engineers with the administrative aspects of the important task of remaining reserves determination and accounting. It was a rather simple program but it opened my eyes to the power of DBMS programming.

When I was Division Drilling and Production Superintendent, I was challenged by my supervisor to create a way to identify oil and gas wells with greater than normal downhole failure rate and cost so that our engineers and field personnel could analyze those wells and find ways to head off additional, costly failures. In response, I developed not just a program but a system comprised of:

1) Field training so as to get consistent and informed failure causes from all field supervisors,
2) Field data capture with error identification so that data quality would be good and time would not be wasted by bad data,
3) A program with special access for administrators and "normal" access for all other users to preserve data integrity,
4) Monthly reporting of likely problem wells to alert staff,
5) Graphics for use in analysis and to aid in the documentation of proposed action to address a discovered problem.

As VP – Operations, I saw the need to give access to operations information to employees across the company. By then the company had developed or purchased commercial software to perform many tasks. Generally, these programs and the data supporting them were only accessible only by the few employees trained to use the specific program. Information lived in silos, and it was difficult to share information across the enterprise. In addition, we not only had databases (neatly structured digital data) but we also had data collections of a variety of formats (scanned documents, maps, spreadsheets, wellbore diagrams, well histories in .pdf and .doc formats, etc.). We needed a way to give access to employees from all areas of our company to all of this information in an intuitive manner. I oversaw in-house programmers who developed this application over a two-year timeframe at a cost of over $350,000 plus ongoing upkeep. This application became a core application for the company.

Q. YOU ALSO MENTIONED THAT YOU MANAGED THE E,H,&S DEPARTMENT. CAN YOU PROVIDE A BIT MORE DETAIL ON YOUR INVOLVEMENT IN THE AREA OF EMISSIONS?

A. For many years the company relied upon each division office to manage safety, safety training, and interaction with state agencies on permitting (including emissions permitting). As VP – Operations, I saw the unevenness of how safety training and environmental permitting and reporting was being accomplished. I hired a professional E,H&S manager to create consistent safety protocols and improve the company's safety training through new field safety representatives. This group also became responsible for adhering to the new Greenhouse Gas Reporting requirements from the EPA and they worked with our facility engineers on emissions permitting (mostly NOIs) for our new and growing facilities in southeast New Mexico. By the time GHG reporting was required, the company had hired a new manager to take responsibility for the E,H,&S department but I stayed closely involved to provide technical understanding and support.

Q. WHAT ARE YOUR PROFESSIONAL AFFILIATIONS, IF ANY?

A. I am a member of the Society of Petroleum Engineers and was selected as a Distinguished Lecturer for their 2020-2021 DL program.

Q. WHAT HAVE YOU BEEN ASKED TO ADDRESS IN YOUR TESTIMONY BEFORE THE BOARD?

A. I will address many aspects of this rule for which my 40+ years of education and experience qualifies me to address. There are other aspects of the rule that require more specific technical expertise and/or experience that I will leave to others to address.

Q. DO YOU HAVE ANY CONCERNS ABOUT ASPECTS OF THE PROPOSED PART 50 RULE THAT ARE TECHNICALLY INFEASIBLE OR UNWORKABLE?

A. NMOGA recognizes that the Oil and Gas industry in New Mexico has a part to play in addressing ozone formation so as to prevent a determination of non-attainment in certain parts of the state. As you will see from others during our direct case, this industry has an opportunity to reduce some emissions and cause a small decrease in ozone formation. I am concerned with some of the proposed requirements that are extraordinarily expensive to attain if not actually unattainable. Further, I am concerned with these extraordinarily expensive requirements' impact to the industry, particularly to jobs, to livelihoods, to communities and even to environmental progress within oil and gas operations that has been made over the last ten years.

Q. WHAT ARE THEY AND WHY ARE THEY TECHNICALLY INFEASIBLE OR UNWORKABLE IN THE OIL AND GAS INDUSTRY IN NEW MEXICO?

A. Produced Water Management Units
Applying storage vessel controls on tank batteries at SWD facilities
Applying vapor balancing or capture for control on produced water transfers
Applying emissions standards even during start-up, shut-down, and malfunctions
EMT
New engine emissions requirements for relocated or temporarily sited machines

Q. DO HAVE ANY CONCERNS ABOUT ASPECTS OF THE PROPOSED PART 50 RULE THAT ARE COUNTERPRODUCTIVE?

A. Yes. There are some aspects that could increase ozone formation and some aspects that will reduce the recycling and utilization of produced water and lead to more fresh water consumption.

Q. WHAT ARE THEY AND WHY ARE THEY COUNTERPRODUCTIVE?

A. As you will see from experts who will follow me, ozone formation in New Mexico in the areas of the state where this rule would apply are "NOx limited". That means that changes in NOx emissions will have a much larger impact on ozone formation than changes in VOC emissions. There are certain aspects of this rule where new requirements will actually convert VOC emissions into NOx emissions by combustion. There are several requirements that could cause ozone formation to increase and should be removed. NMOGA will address each of these in our testimony in this hearing.

Over the past 10 years or so, the industry has voluntarily reduced its consumption of fresh water, especially for well completions by utilizing produced water for fracture stimulation fluid. I don't have the exact figures, but I suspect that fresh water made up close to 100% of "frac water" in 2012. I am proud to say that according to OCD data, that number is now down to below 10% in New Mexico. Produced water reuse and brackish water have supplanted fresh water. This rule threatens to erase all of that progress by putting unattainable limits on Produced Water Management Facilities including lined, high-tech large volume water management ponds. We will provide expert testimony to give you a greater understanding of the challenge that the rules, as written, represent.

Q. AS A FORMER OPERATING EXECUTIVE, WHICH OF THESE ISSUES SEEM MOST LIKELY TO IMPERIL THE FUTURE VIABILITY AND SUCCESS OF THE OIL AND GAS INDUSTRY IN NEW MEXICO?

A. What I see is a need to identify those new requirements that have an outsized cost impact on low production sites with little to no impact on ozone.

Let me offer an example of how such outsized costs might impact the industry and the state: Most operators in New Mexico own and operate low volume production wells and site. Some operators build their business by operating these low production rate wells with careful management of operating costs to extend the life of these assets. These sites operate at low profit margins for the owner and are therefore very susceptible to imposed cost increases. No matter the size of the company, if a new cost is imposed on a low production well or site, that cost must be one that can be repaid in a relatively short period of time, or the owner will make the choice to end production and plug the wells. Note that any wells that are prematurely shut in will impact state revenues as the state was enjoying all of the benefits of severance taxes and, in most cases, royalty payments from that well or site. When a cost is imposed that causes the owner to cease production, the state loses all of that income as that production is stopped. If this rule is implemented as written, it can cause a huge number of wells to cease production, the economic impacts to the owners/operators, their employees, their families, the community, and the state can be profound. That is my understanding from my practical knowledge of the industry. We will present an expert later to quantify the expected impacts of this rule as proposed.

I am especially concerned with the following concepts: EMT (adds enormous costs and complexity with no emissions reduction), Engines and Turbines (some requirements will leave only one vendor whose product can meet the requirements which will lead to a lack of competition and supply chain problems. Other requirements will lead to extraordinary cost and poor incentives to right-size equipment.), Equipment leak inspections (as proposed these requirements are for Audio, Visual, and Olfactory inspections and for Leak Detection and Repair (LDAR) are disproportionately expensive on a $/emission volume basis), Hydrocarbon liquid transfers (requirements that are appropriate where truck loading of oil is frequent enough to warrant the added expense but not in all cases), Pneumatic controllers (again, requirements that are effective and cost effective in certain situations but as proposed will impose huge costs at low producing sites with devastating impact on operators with little impact on ozone in many instances), Storage Vessels (once more, NMOGA will recommend careful application of this reasonable idea to sites where it is cost effective), and Produced water management units (as mentioned above, this requirement will reverse all of the progress made to date in reducing fresh water use and raise costs for operators, therefore reducing development in New Mexico).

Q. FROM AN OPERATING EXECUTIVE'S PERSPECTIVE, ARE THERE ASPECTS OF THE PROPOSED PART 50 RULE THAT MAKE SENSE?

A. Certainly, as I said earlier, NMOGA understands that the oil and gas industry in New Mexico should play a role in reducing ozone formation precursors. We support new, effective and cost-effective regulations. Conceptually many of the proposals have merit but as with many things in life, details matter. You will see NMOGA supporting many new requirements that will have a large reduction in ozone precursor emissions even though those reductions, across the industry, will make only small impacts on ozone according to air/ozone modeling performed for NMED. Contributing to the avoidance of a non-attainment designation in a cost-effective manner that leaves this important industry viable is the right thing to do.

Q. YOU INDICATED THAT THE EQUIPMENT MONITORING TAG (EMT) PROPOSAL IS ONE OF YOUR PRINCIPAL CONCERNS. CAN YOU EXPLAIN TO THE BOARD YOUR CONCERNS?

A. The complexity of what is suggested by this new requirement is staggering. As I described before, my background gives me good insight to be able to understand what would be required to accomplish what the NMED has proposed. Putting tags on equipment is just the start of the difficulties and, while that itself has problems, the system that would be required to input all of the various digital data, documents, field observations, and more into a company's information system and the timelines to retrieve it all would be extremely difficult and very expensive. Even more, such a project for a company that already has databases and data collections for maintenance management and separate databases and data collections for emissions compliance makes the task even more complex, duplicative of already incurred costs, and expensive. The system that I developed using professional programmers is a walk in the park compared to this. In my experience this would likely require at least three years to fully implement, likely more, and cost well over a million dollars for a single operator. Further, it would have to be a custom product or one with a custom integration because it would have to mesh with existing systems so many operators will all have to develop solutions that apply only to their businesses. How a medium to small operator will do this is unfathomable to me. The NMED has apparently based this idea on a commercial software package that does <u>some</u> of what the NMED wants this system to do but it does not do <u>all</u> of what is being required and is totally inappropriate for companies with already established maintenance and emissions information systems already in place. One principal of data management that I have learned over my 40+ year career is to only enter data once. Having parallel systems with supposedly the same data in multiple systems is not only duplicative and resource-intensive but increases the risk of clerical errors. Beside the double work to enter data, there will inevitably be errors and, if found during an audit as proposed by the NMED, will likely be interpreted as some attempt at evasion of the rules or will be viewed as a violation of keeping valid data. Couple the complexity and cost with the fact that this EMT system itself creates virtually zero emissions reductions, you can see that this idea has a cost per ton of reduced emissions that is infinite. The NMED has said that part of the benefit they seek with the EMT system is assurance that what a company says that they do in the way of monitoring, inspecting, etc. they really do. It should not matter to NMED how companies accurately and efficiently store compliance and emissions data. The NMED is looking for reliable data that they can trust but the EMT system that they propose will not achieve that goal and will cost operators millions of dollars and result in no emissions reductions and fewer dollars available for development in New Mexico.

Q. YOU INDICATED THAT THE ENGINES AND TURBINES PROVISIONS IN THE PROPOSAL ARE ONE OF YOUR PRINCIPAL CONCERNS. CAN YOU EXPLAIN TO THE BOARD YOUR CONCERNS AND HOW THEY CAN BE ALLEVIATED?

A. Actually, there are several: The proposed requirements on NOx emissions on some horsepower ranges will result in a situation where only a single provider's engines can meet the emissions requirements in that horsepower range. Monopolies like these are not healthy as they remove competition from the market resulting in potentially higher prices for the goods that are not only desired but <u>required</u> by the rule. This situation also can result in serious supply chain challenges which will work against the NMED's desire for a timely application of these new rules. We will offer evidence from engine manufacturers through our expert witnesses to support this assessment and to offer modifications such that at least two major manufacturers have offerings to meet the new requirements.

Further, unreasonable restrictions on management of existing engines will lead to poor utilization of equipment as operators respond to compliance costs by leaving existing engines in place longer than optimum and experience greater downtime due to repercussions of having to perform in-field maintenance and repairs when a like-kind replacement or temporary swap would allow less downtime and better engine work in a shop setting.

Q. YOU INDICATED EARLIER THAT THERE ARE WORKABILITY ISSUES FROM A PRACTICAL PERSPECTIVE WITH THE HYDROCARBON LIQUID TRANSFER PROVISIONS OF THE PROPOSED RULE. CAN YOU EXPLAIN TO THE BOARD YOUR CONCERNS AND HOW THEY CAN BE ALLEVIATED?

A. NMOGA supports capturing significant volumes of hydrocarbon vapors (containing VOCs) that are associated with hydrocarbon liquid transfer from storage tanks to transport trucks or rail cars. Just as with other aspects of the proposed rule, it is good when applied to the right circumstances but is economically infeasible in others. First, we want to ensure that we are addressing hydrocarbon liquids only. I say that because the definition of "Liquid Transfer" could imply that this rule would apply to transfer of produced water to transport trucks. Assuming that this rule applies only to hydrocarbon liquids (crude oil, condensate and intermediate hydrocarbons) let me offer my personal expectations for how this might impact the industry:

This rule would be economically impractical for tank batteries that experience very few loadouts per year. Those tank batteries that sell oil through a connected pipeline may not have a truck loadout for several years if there are no malfunctions on the oil pipeline. The expense of equipping such a facility for vapor balancing or vapor control would be extremely high on a $/VOC reduction basis. As crude oil pipelines are typically very reliable, it seems unnecessary to apply this to tank batteries that sell oil by pipeline. Further, there are many gas wells in New Mexico that produce very low volumes of liquid hydrocarbons (typically condensate). There too, equipping a tank battery with such equipment to capture vapors just a few times per year is economically impractical on a $/VOC volume basis.

This is why NMOGA recommends excluding tank batteries that have loadouts equal to or fewer than 12 time per calendar year or to tank batteries connected to active oil pipelines from this section.

Q. DO YOU BELIEVE THE PROPOSED RULE SHOULD UNAMBIGUOUSLY SET FORTH THE GEOGRAPHIC SCOPE THAT IT COVERS TO PROVIDE NOTICE TO YOUR MEMBERS SO THEY CAN COMPLY?

A. Yes. This rule should be clear where these rules apply and should establish a clear legal public process for including other counties in the future should they become subject to the rule. NMOGA believes that this should not be solely an agency decision but should be part of a robust, data-driven process of the Environmental Improvement Board. Those affected by this major rulemaking should not be left to wonder or guess if their operations will be impacted or not. Further, by identifying in this rule what counties are to be impacted on the effective date, all stakeholders will have the opportunity to support or challenge that determination publicly.

Q. DO YOU BELIEVE THAT FUTURE REVISIONS, IF ANY, TO THE PROPOSED RULE WOULD NEED TO PROVIDE SOME TRANSITION TIME FOR YOUR INDUSTRY GIVEN ITS SCOPE, BREADTH AND DEPTH?

A. Certainly. Even the portions of this rule that NMOGA supports are complex and require engineering design and/or procurement of complicated equipment, or significant capital, or a combination of all to become compliant. NMOGA has suggested reasonable timeframes for compliance for these rules. Should a new area be added to the rule after a proper process, similar timeframes should be applied to sites in those new areas.

Q. WOULD THAT FUTURE TRANSITION TIME NEED TO BE SOMEWHAT SIMILAR TO THAT DEVELOPED IN THIS INITIAL RULE, ADJUSTED FOR THE NUMBER OF AFFECTED FACILITIES? WHY OR WHY NOT?

A. Yes. As more facilities are affected, personnel, capital, and supply chain constraints become more pronounced. This reality should be considered if future additions are made to the areas covered.

<u>PROPOSED 20.2.50.7 DEFINITIONS</u>

Q. TURNING TO PROPOSED 20.2.50.7 DEFINITIONS, AS AN INDUSTRY EXECUTIVE ARE THERE ANY OF THESE DEFINITIONS WHICH CAUSE YOU CONCERN?

A. Team, are there more that should be addressed in addition to the ones listed below?

Q. TURNING TO THE DEFINITION OF BLEED RATE IN PROPOSED 20.2.50.7(C), DOES INDUSTRY REGARD INTERMITTENT PNEUMATIC CONTROLLERS AS HAVING A BLEED RATE?

A. As will be addressed in more detail by others, getting the definition of pneumatic devices correct is critical to proper application of whatever rule the EIB adopts. Pneumatic devices such as pumps and controllers are devices that are powered by a pressurized gas such as natural gas, air, nitrogen, etc. Focusing on pneumatic controllers, these pneumatic devices are used to manage some process such as maintaining a particular pressure or temperature, or they can be used to control a valve that will maintain a liquid level within an acceptable range. Some pneumatic controllers are designed to emit a stream of the driving gas continually between actuations and will change in their emission rate when activating some end device. The rate at which these types of controllers emit the driving gas is called its “bleed rate”. There are a class of such continuous bleed controllers that bleed at more than 6 scf/hr (high-bleed) and another class that bleed at a rate below 6 scf/hr (low-bleed). Since the normal rate of emissions for these devices is, in essence, the bleed rate, it is straightforward to estimate emissions from them and, therefore, to estimate the reduction in emissions should one be replaced by a non-emitting device. But there is another class of pneumatic controller – intermittent pneumatic controllers - that is designed to operate very differently: they are designed to only emit when actuated. This usually results in a controller that has lower emissions than even a low-bleed device but, since it matters how often the controller is called upon to actuate, it is not straightforward to estimate its emissions. Normally operating intermittent controllers therefore do not have a bleed rate. NMOGA has taken care to make suggested changes to the rule that are consistent with the fact that intermittent controllers do not have a bleed rate as we support the minimization of high-bleed controllers to only where their unique capabilities are needed for safe operations.

Q. IN THE DEFINITION OF “COMMENCE OF OPERATION” IN PROPOSED 20.2.50.7 (G), WHY SHOULD THE PHRASE “BUT NO LATER THAN THE END OF WELL COMPLETION OPERATIONS” BE STRUCK?

A. There can be a significant time delay between when a first well being served by a well production facility is completed and when it begins normal production to sales. This is especially true now, after the new OCD Waste Rule became effective. A well can be drilled and completed and, after separation flowback through temporary equipment on the well site, may be shut in awaiting completion of the well production facilities and the gas gathering pipeline. During that waiting period, no oil or gas is being produced through the well production facilities. Monitoring, inspecting, etc. would not be necessary during that time. Such requirements of this rule should be applied only once production through permanent production facilities to sales begins.

Q. IN THE DEFINITION OF "CONSTRUCTION" IN PROPOSED 20.2.50.7(J), WHAT IS THE PRACTICAL PROBLEM WITH INCLUDING RELOCATION AND WHY HAS NMOGA SUGGESTED EXCLUDING RELOCATIONS AND REPLACEMENTS IN KIND?

A. Production rates will change across time as new wells are constructed and added to a well production facility, as wells produce and deplete, and as equipment needs change at the facility, for example, a change in the volume of supply gas needed for gas lift over time. It would be best if operators could change an existing compressor at a facility (which may be operating under the requirements for an existing engine) with another compressor from inventory or from another existing site to right-size it to match the demand. From my experience, let me describe how this might actually work out in the field:

If the simple relocation of a compressor triggered new, tougher emissions requirements that only a new engine could meet, operators would be reluctant to move an existing machine even though it was not operating efficiently. Further, I could see a strategy of installing multiple smaller compressors at a facility before this rule is effective so that these smaller compressors could be turned on or off as needed to give the operator flexibility even though smaller machines are not as efficient in terms of emissions.

Over time, compressor fleets will naturally transition by retiring older, less efficient machines and replacing them with newer, more efficient machines. It is economically impractical to force the purchase of a new machine simply because it is relocated.

Further, consider that sometimes operators will swap an engine in the field with a similar machine (like-kind) so that maintenance can be performed in a shop setting. This can result in better maintenance work due to the shop setting and it can reduce downtime, and perhaps emissions, as another benefit. Causing a "swapped" engine to be subject to more stringent requirements just because it was swapped out for maintenance is economically impractical. NMOGA recommends that this rule be modified to prevent such results.

Engines need to be taken out of service from time to time for maintenance or repair, and operators need flexibility to use replacement engines to continue operations. NMOGA is concerned that this routine activity may subject replacement of existing engines to "new" emissions standards based on NMED's broad definition of construction.

Q. WHY DID NMOGA PROPOSED TO DELETE THE DEFINITION OF "CUSTODY TRANSFER" FROM PROPOSED 20.2.50.7(K)?

A. The term Custody Transfer is only used as part of another defined term, "Local distribution company custody transfer station". This definition of Custody Transfer is unnecessary and can cause confusion with no benefit.

Q. WHAT WERE THE PROBLEMS WITH THE PROPOSED DEFINITION OF "GATHERING AND BOOSTING STATION," IN PROPOSED 20.2.50.7(Q) WHAT HAS NMOGA PROPOSED TO REPLACE IT, AND HOW DOES THE NMOGA APPROACH MAKE THIS DEFINITION WORK BETTER FOR HOW THE OIL AND GAS INDUSTRY IS STRUCTURED IN NEW MEXICO?

A. As originally written the definition was likely to create confusion. As an example, a well production facility, which we believe is not intended to be considered a gathering and boosting station, could fit that definition just as easily as a gas gathering system compression station, which we believe is intended. NMOGA is proposing definitions for various facilities that are subject to this rule that conform to the actual facilities that exist in the field using terms that are familiar to the industry and inclusive of as many expected facilities as possible. We have been careful to not create "gaps" or "overlaps" in the rule coverage so that it will be clear which requirements are applicable at every facility type.

Q. WHAT IS THE PROBLEM WITH THE DEFINITION OF "HYDROCARBON LIQUID" IN PROPOSED 20.2.50.7?

A. This definition indicates that it does not include produced water but because produced water can contain a very small amount of hydrocarbon liquids, NMOGA wanted the definition to be clear as to what was intended, which means excluding produced water. We do not believe that this is a conceptual change but a change to increase clarity. This clarification is especially necessary since, unless modified as NMOGA suggests, the definition of "Liquid Transfer" includes the term produced water. NMOGA's recommendations in both of these definitions will create clarity as to how these rules apply.

Q. WHY IS THE AMBIGUITY OVER WHETHER PRODUCED WATER IS INCLUDED IN THE DEFINITION CREATE PROBLEMS?

A. Hydrocarbon Liquid Transfer section seems to be applicable only to the transfer of oil, condensate and intermediate hydrocarbons and not to water. This is reasonable and NMOGA supports those proposed requirements with modifications. Applying those requirements on produced water transfer would be technically infeasible in many instances and impractical in all instances. We want this definition to clear as to what is covered and what is not.

Q. IS A SIMILAR CHANGE REQUIRED TO THE DEFINITION OF "LIQUID TRANSFER" IN PROPOSED 20.2.50.7(U)?

A. Yes. Again, there is a huge difference in the industry's ability to manage vapors containing VOCs when transferring hydrocarbon liquids vs transferring produced water to tanker trucks or rail cars. Managing vapors while transferring hydrocarbon liquids will cause the industry to install and use new vapor management equipment and to have tanker truck and rail car tanks tested to a new, higher standard. These new requirements might be accomplished at a reasonable cost per ton of VOC emission reduction in facilities that regularly utilize trucking or rail to transfer crude oil and condensates. Trying to apply those same requirements on produced water transfer would result in very limited emissions reductions and impose high costs on trucking companies.

Q. WHAT IS THE PROBLEM WITH THE PROPOSED DEFINITION OF "NATURAL GAS COMPRESSOR STATION," IN PROPOSED 20.2.50.7(W), WHAT IS NMOGA'S PROPOSAL, AND HOW DOES THAT SOLVE THE PROBLEMS?

A. As mentioned in NMOGA's comments on the Gathering and Boosting Station definition, NMOGA is trying to provide clarity in describing the various facilities that exist in the industry without "gaps" or "overlaps". Compressor stations that are situated downstream of a natural gas processing plant (or, in a few cases, downstream of a natural gas gathering system) facilitate the movement of end user quality gas (pipeline quality gas) through a transmission pipeline system. These are not compressors at well sites, well production facilities or at gathering and boosting stations and the applicable definition should be clear to distinguish them as such. *Those located at gathering and boosting sites are already included in the term "gathering and boosting site," which includes permanent installations, such as compressor stations, downstream of production and upstream of the natural gas processing plant. The only other type of compressor station under the terms of the rule is transmission compressor stations, which are included in this revised definition.*

Q. WHAT ISSUES DO YOU SEE WITH THE DEFINITION OF "PNEUMATIC CONTROLLER" IN PROPOSED 20.2.50.7(EE)?

A NMOGA believes that this definition should be more complete since we expect different requirements on the different types of pneumatic controllers. Continuous bleed controllers (high or low) are designed and operate very differently than intermittent pneumatic controllers and these differences should be recognized in the requirements. Further, there are time when a pneumatic controller can have its exhaust gas captured and routed to a control device which would make those controllers non-emitting, regardless of their underlying design. By ensuring clarity in the definitions, we can create more clarity in the pneumatic controller and pumps section.

Q. DID YOU HAVE A CONCERN WITH THE DEFINITION OF "PRODUCED WATER" AS FOUND IN PROPOSED 20.2.50.7(HH)?

A. First, as a technical correction, NMOGA suggests that the word "liquid" be used rather than "fluid". Water is a fluid when it is in gas phase (steam) or in liquid phase. The term liquid is more correct in context of produced water. Second, there are liquids that are used in association with the process of drilling a new well, but these liquids are brought to the well construction site and are used in the drilling process and then moved to a subsequent site for reuse or disposed of in a regulated manner. It should not be confused with water that is either pumped into a well during the completion phase for hydraulic fracture stimulation and later flowed back to the surface or with water that is produced naturally with oil and gas from the producing geologic formation. Both "frac water" and water produced naturally along with oil and gas should be considered "produced water".

Q. WHAT WOULD YOU PROPOSE INSTEAD?

A. As you can see, NMOGA recommends striking the term "drilling for" and including liquids that stem from the completion process and from normal production after the fracture fluids have been recovered. This actually adds the completion phase water volumes to the definition and properly excludes liquids that are used only for the drilling phase.

Q. WHY IS NMOGA PROPOSING A DEFINITION OF "TANK BATTERY."

A. Again, NMOGA is trying to create a set of clear definitions of facilities used in the industry with no "gaps" or "overlaps" to provide clarity as to how these requirements apply. The term "tank battery (or "tank batteries") is used in the rule multiple times but is not defined. NMOGA believes that by adding this definition, the rule will be more clear. Tank batteries (including single tanks or multiple tanks) are often a component of a Well Production Facilities. Tanks that are associated exclusively with a salt water disposal well/facility (SWD) should not be included in the requirements of this rule as produced water routed through or stored in such tanks contains mostly water with perhaps a very small skim of hydrocarbon liquid that is already flashed to a non-volatilizing liquid and therefore has very low potential for VOC emissions. The cost to try to manage any small amounts of vapors associated with such tanks at an SWD facility would be enormously expensive on a $/VOC emission basis and would be economically infeasible.

Q. WHAT ARE VAPOR RECOVERY UNITS AND HOW DO THEY DIFFER FROM VAPOR RECVERY CONTROL UNITS? HOW DO THE "PROCESS" AND "CONTROL" RELATE TO THESE ITEMS?

A. The terms "Vapor Recovery Unit or VRU" and "Vapor Recovery Control Unit or VRCU" have critical distinctions. Often the equipment is the exact same (other than perhaps size), making it difficult to distinguish between the two visually. The difference is whether the device is capturing sufficient gas volumes to be a profitable part of the production to sales process, or if the device is only on site for emissions reduction. One way to determine if the unit is a VRU or a VRCU is if the cost to purchase, install, and operate the device returns a profit to the operator or it does not and is therefore primarily deployed for emissions reduction purposes. Those that are installed for profitable gas recovery and sales are Vapor Recovery Units. Those are installed only to reduce emissions are Vapor Recovery Control Units.

The EPA has created a method to help operators to make the determination: Criteria for Determining whether Equipment is Air Pollution Control Equipment or Process Equipment (epa.gov) The EPA believes that the following list of questions should be considered in making such case-by-case judgements as to whether certain devices or practices should be treated as pollution controls or an inherent to the process:. 1. Is the primary purpose of the equipment to control air pollution? 2. Where the equipment is recovering product, how do the cost savings from the product recovery compare to the cost of the equipment? 3. Would the equipment be installed if no air quality regulations are in place? If the answers to these questions suggest that equipment should be considered as an inherent part of the process, then the effect of the equipment or practices can be taken into account in calculating potential emissions regardless of whether enforceable limitations are in effect.

Q. WHAT CONCERNS DO YOU HAVE WITH THE DEFINITION OF "WELLHEAD SITE" IN PROPOSED 20.2.50.7(UU)?

A. Once again, NMOGA is trying to create a good set of definitions with no "gaps" or "overlaps". Wellheads can be located on pads with no facilities other than the well itself and some (likely buried) piping and they can also be located on pads that contain production facilities like separators, pumps, tanks, compressors, etc. The modification that NMOGA offers here to replace the term "Wellhead site", which can be nonsensical in many circumstances as respects this rule, with "Well Production Facility" which is a much more appropriate description for where the proposed rules would be effective. This change is intended to provide clarity while preserving what NMOGA believes is the intent of the rule.

<u>PROPOSED 20.2.50.111 APPLICABILITY</u>

Q. IN PROPOSED 20.2.50.111, SUBSECTION B, THERE IS A REFERENCE TO HAVING A CALCULATION CERTIFIED BY A "QUALIFIED PROFESSIONAL ENGINEER." WHAT CONCERNS DO YOU HAVE, AS AN OIL INDUSTRY PROFESSIONAL, WITH CONDITIONS REFERRING TO "QUALIFIED PROFESSIONAL ENGINEERS" IN THIS CASE AND GENERALLY THROUGHOUT THE PROPOSED RULE?

A. Requiring a professional engineer (which we believe means a registered, professional engineer) might sound like it provides a level of quality and assurance to some of the aspects of this rule, but it does not. Again, from my experience let me describe how this is likely to work out on the ground:

I have known many registered professional engineers in my career and most, if not all of them, while experts in their field, would not know enough about ozone precursor emissions and the proposed regulated activities in this rule that NMED is asking for a professional engineer to manage. Most, if not all of them, would have to be specifically trained in the particulars called for in this rule. They are all qualified in their field or fields on the fundamentals of the engineering of their chosen field but that does not mean that they have specific knowledge, for example, of a control valve's requirement to utilize a high-bleed pneumatic controller in certain situations. On the other hand, there are many qualified persons who might not even be engineers at all who are very qualified to make that same assessment, such as qualified company employees. Requiring a professional engineer to review certain aspect of this rule rather than allowing other, qualified and trained persons, including properly trained company employees, will create a human resource bottleneck that will hinder the application of this rule and cause additional costs of implementation that are not necessary nor cost effective for no discernable benefit.

Q. IN PROPOSED 20.2.50.112, THERE ARE REFERENCES TO "OPERATION AND MAINTENANCE" CONSISTENT WITH "MANUFACTURERS SPECIFICATIONS" AND THE PROPOSAL CALLS FOR THESE TO BE MAINTAINED. WHAT CONCERNS DO YOU HAVE, AS AN OIL INDUSTRY PROFESSIONAL, WITH THIS REQUIREMENT?

A. To address this, I need to rely on my own experience of how the oilfield operates to provice insight as to how this concept might actually work out:

Compliance with manufacturer specifications seems to be something that should always result in better performance, but it will not. Operators might not even have some equipment manufacturers specifications on equipment that has been operating for a long time and might not even be available anymore. Consider that these manufacturer specifications were not necessarily devised with the advantage of operating the manufactured equipment for as long a time that some operators have accumulated over many years. These operators have the opportunity to put into place better maintenance protocols than even the ones that came with the original equipment. The original specifications were based on design and perceived good general operating practices. Operators have had perhaps experience operating many machines over perhaps many years to improve and optimize these practices. Further, consider that these original maintenance specifications were likely not based on minimizing emissions but were based on, perhaps, operational reliability or optimum operating cost.

NMOGA recommends that operators be allowed to establish written maintenance protocols for the equipment that they operate and their actual maintenance be judged against those internally established standards.

Q. HOW CAN THOSE CONCERNS BE ADDRESSED WHILE PRESERVING AN OBJECTIVE INDICATOR OF WHAT OPERATORS ARE DOING TO ENSURE GOOD PRACTICE IS BEING FOLLOWED?

A. NMOGA believes that operators should have the opportunity to develop their own practices but be held accountable for adhering to them. Maintenance practices should be written, and records maintained for inspection by the NMED to ensure that whatever practices are established are being met.

Q. IN PROPOSED 20.2.50.112, SUBSECTION A.(2), NMOGA PROPOSED LANGUAGE FROM THE FEDERAL NATIONAL EMISSIONS STANDARDS FOR HAZARDOUS AIR POLLUTANTS IN LIEU OF NMED'S PROPOSED "SHALL BE OPERATED TO MINIMIZE EMISSIONS OF AIR CONTAMINANTS, INCLUDING VOC AND NOx." WHAT IS NMOGA'S CONCERN WITH THAT LANGUAGE AND HOW DOES NMOGA'S PROPOSED CHANGES ADDRESS THAT CONCERN?

A. It is unrealistic to require the same emissions control requirements on a unit during startup, shutdown, or malfunction as you might during normal running operation. The original language created a duty that is inconsistent with realistic operations and unachievable in practice. The suggested NMOGA language establishes a duty to perform these non-normal operations in a manner that is consistent with good operating practice for emissions reduction but does not penalize an operator for outsized emissions during these unusual time periods. Further, operators should not be penalized for not achieving emissions reductions that are beyond what is required under this rule, even if they can be achieved. Such reductions should be voluntary. The federal language, as cleaned up to minimize SSM conflicts, represents a good resolution of this issue that was reached after extensive notice and comment.

Q. PROPOSED 20.2.50.112, SUBSECTION A.(3) CREATES THE CONCEPT OF AN "EQUIPMENT MONITORING TAG" OR EMT. WHAT ARE YOUR CONCERNS WITH THIS CONCEPT?

A. The EMT system that is being proposed by NMED has no precedent that industry can look to for deep understanding of how this will work as it is deployed. In the absence of such precedent, I will offer my perception of how this will work out based on my experience and understanding of the business. In addition to my earlier comments about potential errors in data entry, this particular facet of the larger EMT system that NMED is proposing has its own problems. First, at many Well Production Facilities, there are likely dozens of components that would require a tag. These tags must endure very tough environmental conditions including incessant UV radiation from the sun, winds of 30-60+ mph, rain, hail, dust storms, ice, and so forth. There may be many ways that operators try to comply with this facet of the rule and many of them will fail over time as operators and vendors try to invent a tag that can withstand these extreme conditions. The cost of installing (and reinstalling) these tags will be accompanied by virtually zero emissions reduction and therefore virtually zero impact on ozone formation.

Q. ARE THE FIELD SCANNING, DATABASE INTEGRATION AND RELATED ISSUES CONCERNING TO YOU?

A. Yes. These facets of this complicated, expensive, and likely ineffective EMT system are all a part of an attempt to prove that an operator has actually done what they say that they have done. The fact that an operator has so many ways around this result should they want to cheat should be obvious. The vast majority of operators try to comply with regulations. If there are a few that cheat, this should not cause the rest of the industry to spend millions of dollars developing complex and expensive systems that do almost nothing to reduce ozone precursors.

Q. IN YOUR EXPERIENCE, IS INDUSTRY OPPOSED TO PROVIDING THE TYPE OF INFORMATION DESCRIBED IN THE "COMPLIANCE DATA REPORT"?

A. If the NMED wants companies to provide compliance data reports without the unnecessary complexity of tags and field scanning of events, the industry is willing to provide such reports within a reasonable timeframe. Even this alternative will take a significant effort as the data that NMED desires in such a report likely is stored in multiple databases and data collections within a company. Creating a report that spans multiple in-house sources is still going to be a big and expensive challenge that will take time to implement but the industry is willing to comply. To do this will require careful planning so that what data is needed from each source/section of the rule is identified at the outset, the report carefully designed with input of the regulated community, and DOES NOT CHANGE once in place.

Q. IN YOUR EXPERIENCE, ARE THERE TIMES WHEN A THIRD PARTY MAY GET SOMETHING WRONG IN AUDITING A FACILITY?

A. Yes. I have seen this myself. Misinterpretation of information has and can cause a third party to err in their assessment of a situation. Third parties are not invulnerable. In fact, the fact that they are supposed to be independent can lead to misinterpretation. Third party auditors may rely on their interpretation of documents and data without sufficient context from company employees who create or use the information and, without that context, third party personnel can simply err in their opinions. I have personally experienced this. Once this type of error was explained to auditors that reviewed operations under my authority, and the auditor did further research to confirm the facts, their error was corrected. This rule should recognize that and include a process for an operator to challenge both the findings of a third-party audit report and any recommendations that stem from that review. If proper process is established in the rule, all parties are protected. This concept has already been adopted by the OCD in their recent Waste Rule. NMOGA recommends that this rule include such fair protections for all parties.

Q. IN YOUR EXPERIENCE IN THE INDUSTRY, DO REGULATIONS SOMETIMES PROVIDE THE POSSIBILITY OF AN ALTERNATIVE MONITORING PLAN SUBJECT TO AGENCY APPROVAL?

A. Certainly. This is just good practice as a one-size fits all approach is rarely the optimum way to achieve a particular goal. Adding the option for a NMED-approved alternate monitoring plan allows operators to innovate and reach the goals of the agency at, perhaps a lower cost, than would have been achieved through the explicit requirements of the rule. Consider that this rule may be in place for many years. Time will allow new technologies to be developed and/or creative techniques to be developed that, if deployed, could allow compliance at a lower impact. NMED would remain in control as any such plan would have to be first approved, and then monitored to effectiveness. From my experience, a simple example might be that a site has two gas fired compressors. One may be operating slightly above the required emissions levels but the operator might install another that operates well below the standard so that, combined, the site meets the rule's objective. Allowing such a plan would achieve the rule's objective at a more reasonable cost to the operator.

Q. WHAT ARE THE BENEFITS OF SUCH AN ALTERNATIVE MONITORING PLAN FOR BOTH AGENCY AND COMPANY?

A. NMOGA has serious concerns about the technical and economic feasibility of this rule, particularly when the reductions are applied on a per-engine basis. By allowing owners and operators to achieve the emissions reductions on a total allowable regulated emissions basis, owners and operators will be able to achieve the same environmental benefits without incurring unnecessary costs.

Q. DO YOU RECOMMEND THAT SUCH AN ALTERNATIVE MONITORING PLAN PROVISION BE INCLUDED IN THE PROPOSED 20.2.50 RULE?

A. Yes. NMOGA has added language in the rule to allow for such an option. NMOGA endorses that common-sense approach.

Q. IN PROPOSED 20.2.50.112, SUBSECTION C.(3), NMED HAS PROPOSED THAT "BEFORE A 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." IS THIS WORKABLE IN THE OIL FIELD? WHY OR WHY NOT?

A. This can best be addressed using my own experiences to help explain some of the practical aspects of how industry manages transactions. Transactions can be very complicated and many times secrecy is of the utmost importance as negotiations are ongoing. I witnessed this first-hand as the company I worked for negotiated for a very long period of time before reaching an agreement to proceed with a sale of the company. Should word have gotten out, this likely would have scuttled the deal entirely. Public markets are complicated and those companies who participate in them have certain duties for disclosure that could be triggered by word of secret negotiations being disclosed. Having to perform some kind of compliance review of properties that may be "in play" could reveal to employees, contractors, working interest owners, and competitors that a deal is being considered. Further, many negotiations never reach a final agreement to buy/sell and this may not be known until the very last minute. Owners and operators enter into transactions to buy/sell with clear awareness and the experience to know that regulatory compliance is a matter to be considered in the negotiation. How costs to achieve an agreed-to level of compliance should be a private matter to be addressed in the negotiations themselves, not imposed by an outside agency. The new owner (who may or may not even be the operator) will have the responsibility of compliance and costs attendant thereto. Finally, this requirement has no reasonable relationship to the statutory requirement to regulate sources in areas that exceed 95% of the ozone NAAQS and it does not meet the statutory criteria to be more stringent than federal standard. EPA has no such regulations and this interference in an arms-length negotiation has no relationship to protecting public health and the environment.

Q. BASED ON YOUR EXPERIENCE AS AN OPERATING EXECUTIVE, WHAT IS LIKELY TO HAPPEN TO UNITS AND EQUIPMENT OWNED BY A FINANCIALLY DISTRESSED OPERATOR IF THIS PROVISION IS ADOPTED?

A. One of the things that an operator who find themself in difficult financial circumstances may be able to rely upon is the ability of a buyer to see value in that stressed company's assets that they can develop and therefor create more value than the purchase price. Sometimes a buyer will agree to take on properties with a few "warts" in order to gain access to development opportunities that the seller has not pursued for one reason or another. By forcing a seller to be in full compliance before a transaction, that seller may not be able to sell their property. Should they not have the resources to come into compliance, they may have to abandon the property because they have no other viable choice thus creating a burden on the state. If a distressed seller can sell to a more capable operator, the new owner will be responsible, and likely more capable for compliance with NMED regulations. Again, NMOGA recommends that NMED not get involved in the complicated area of buy/sell.

Q. PROPOSED 20.2.50.112(D) REQUIRES THAT OWNERS AND OPERATORS PRODUCE A REPORT WITHIN 24 HOURS OF REQUEST BY NMED. IS THIS FEASIBLE IN YOUR VIEW?

A. No. Assuming NMED and industry works together to design a Compliance Database Report and time is given to implement such a tool, it is unreasonable and unnecessary for operators to be required to submit such reports within 24 hours. Some systems will be very automated, and some will require some staff time to compile depending on the operator. Allowing three days for a report of a single facility is more reasonable. Should NMED request such a report for multiple facilities, more time should be allowed as to be determined on a case-by-case basis between the operator and NMED.

<u>PROPOSED 20.2.50.113 ENGINES AND TURBINES</u>

Q. AS A FORMER OPERATING EXECUTIVE, WHAT IS THE CONCERN ABOUT PULLING PORTABLE NON-ROAD ENGINES INTO THIS RULE AS IS DONE IN PROPOSED 20.2.50.113, SUBSECTION A?

A. Non-road portable engines by their very nature can be moved quite often. If the existing definition of construction is retained, the relocation of portable engines will subject existing to requirements to those for new engines. Many of these engines cannot be retrofitted to meet such requirements and would have to be retired at an unreasonable cost. Non-road engines are also subject to exclusive federal regulations to prevent different state standards from interfering with interstate commerce. Portable engines are very likely to cross state lines in both of the major operating areas of the state so NMED's proposed rules would interfere with that practice.

Q. IS THE PROPOSED 20.2.50.113 ENGINE AND TURBINE PROVISION ONE WHERE THE ALLOWANCE FOR AN ALTERNATIVE COMPLIANCE PLAN IS USEFUL?

A. Yes. This section, perhaps more than most, lends itself to an alternative compliance plan.

Q. EXPLAIN HOW SUCH A PLAN BENEFITS BOTH NMED AND THE OPERATOR?

A. Giving operators to flexibility to meet an emissions limit on, as an example, a fleet-wide basis could mean achieving the limit at a much lower cost to the operator. Allowing an operator to use a mixture of newer and older but modified, lower emitting engines that exceed the emissions requirements while allowing some existing engines, that themselves might not meet the normal requirements, could achieve the overall emissions goals at a much lower cost than either replacing or adding emissions controls on more existing machines. That is a clear advantage to operators while achieving NMED's goals. NMED, of course, would stay in control since they would have to approve the plan and the operator would have to comply and continue monitoring to ensure that the expected emissions reductions were actually delivered. This would benefit NMED as it would be less burdensome to oversee a fleet-wide program than have to ensure that every engine met its individual requirements.

Q. WOULD EMISSIONS BE REDUCED AT THE SAME LEVEL UNDER SUCH A PLAN?

A. Yes, I would not expect the NMED to approve a plan unless that were true so it is in NMED's control to ensure that result.

Q. AS A FORMER OPERATING EXECUTIVE, WHAT ARE YOUR BIGGEST CONCERNS ABOUT HOW THE PROPOSED EMISSIONS STANDARDS WOULD AFFECT USE OF ENGINES AND TURBINES IN THE FIELD?

A. There are two: first that the NMED does not create a situation where only one major vendor's engines or turbines can meet the requirements and second, that the costs to comply are not excessive on a $/ton of emissions basis.

Q. WHY IS IT BENEFICIAL FOR OWNERS AND OPERATORS TO BE ABLE TO MOVE UNITS FROM PLACE TO PLACE IN THE FIELD?

A. See above in definitions regarding relocation.

Q. IF AN OVERSIZED UNIT IS USED, DOES IT RUN AS EFFICIENTLY?

A. No. That is one of the examples of how a rule that seems good can have negative unintended consequences when it is applied. Making operators spend a lot of money to replace or upgrade (if possible) an engine that is in compliance as an existing engine but would not be compliant if moved creates a serious disincentive for operators to optimize engines and may therefor cause engines to be less optimized, which can certainly result in more emissions than necessary.

PROPOSED 20.2.50.114 COMPRESSOR SEALS

Q. AS A FORMER INDUSTRY EXECUTIVE, DO YOU SEE MUCH, IF ANY, BENEFIT IN THE COMPRESSOR SEAL STANDARDS AT 20.2.50.114? WHY OR WHY NOT?

A. Compressor seals are a very small source of ozone precursor emissions. The impact of these emissions on ozone are so small as to be inconsequential. We already have requirements at many sites for compressor seals to be changed every 26,000 operating hours or 3 years (whichever is later). Further, using sub-atmospheric pressure (negative gauge pressure) on compressor seal areas to capture these very small volumes can cause safety and other operational problems that are not warranted. Unless the NMED chooses to eliminate this section due to its very small impact and the great cost on a $/volume of emissions basis, NMOGA could support the option of collecting these small gas volumes, without negative pressures being applied, in order to route them to a control device.

PROPOSED 20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS

Q. ARE CERTAIN OPERATIONS IN THE OIL INDUSTRY ALREADY SUBJECT TO LEAK DETECTION AND REPAIR REQUIREMENTS UNDER OTHER PROGRAMS?

A. Yes. Operators of many well production facilities in NM are required to perform and document Audio, Visual, Olfactory (AVO) inspections on a weekly basis and in no case are operators are to perform AVO inspections on less than once per month. Further, operators of many well production facilities are already required to perform what is known as Leak Detection and Repair (LDAR) using sophisticated optical imaging equipment that has the ability to "see" methane or specific gas detector devices that have the capability to detect methane. Operators are also subject to the leak detection and repair requirements under federal rules, most notably NSPS OOOOa. These LDAR inspections are required under federal rules.

Q. DOES IT MAKE SENSE TO HAVE THE SAME EQUIPMENT SUBJECT TO MULTIPLE LEAK DETECTION AND REPAIR REQUIREMENTS OR DOES THAT ADD CONFUSION ABOUT APPLICABLE STANDARDS AND PROCEDURES?

A. It is important that requirements for leak detection and repair be thought through carefully and coordinated so that requirements under various jurisdictions align in order to get the results needed without undue expense burden, waste of valuable human resources, or unintended gaps or overlaps in coverage due to conflicting expectations by multiple agencies.

Q. AS WRITTEN DOES PROPOSED 20.2.50.116 AND ITS APPLICATION TO "ASSOCIATED PIPING AND COMPONENTS" POTENTIALLY INCLUDE NON-VOC EMITTING SOURCES LIKE WATER, INSTRUMENT AIR AND STEAM?

A. It appears that NMED intended to apply LDAR requirements for components that, in fact, have some ability to lead methane. NMOGA has made a suggested modification to the language to make that clear.

Q. IS THERE ANY ENVIRONMENTAL BENEFIT TO THAT?

A. It does not make sense to use instruments designed to detect methane on components that do not contain methane.

Q. IS THAT WHY NMOGA PROPOSED TO EXCLUDE "COMPONENTS IN WATER AND/OR AIR SERVICE" FROM THESE REQUIREMENTS?

A. Yes. These components should be excluded since they have virtually no possibility to leak methane and performing LDAR on them would be a waste of effort, human resources, and time.

Q. IN PROPOSED 20.2.50.116, SUBSECTION D.(2)(a), WHY IS IT ONLY FEASIBLE TO PROVIDE NOTICE OF THE "FIRST" ALTERNATIVE MONITORING EVENT AND NOT EVERY EVENT?

A. If an operator has worked with NMED to establish an alternative equipment leak monitoring plan, the operator should notify NMED before it begins to implement that plan (15 days prior to the first monitoring). NMED may want to send inspection personnel to witness the first monitoring event to ensure that what was agreed to as an acceptable alternate program is being implemented as expected. Once in place though, these programs could involve thousands of monitoring events each year. It is unreasonable for operators to have to inform NMED 15 days before each event and equally unreasonable to expect NMED to send field personnel to witness these events. Schedule changes due to employee sickness, weather, detector malfunction, and other events outside of the operator's control will cause many scheduled events to be rescheduled and then cause problems ensuring that all required monitoring events are accomplished if they have to be delayed in order to provide a new 15-day notice to NMED. This is a logistical nightmare for little if any value. If NMED wants to observe additional monitoring events, they can reach out to operators and work out such opportunities.

Q. DOES THE PROPOSAL ADEQUATELY ADDRESS THE REASONS FOR DELAY OF REPAIR? WHAT IF AN OPERATOR IS SHORT OF PARTS OR NEEDS A SPECIALIST TECHNICIAN TO DO WORK THAT IS NOT AVAILABLE?

A. No. It is unreasonable to require operators to store spare parts or replacement components for every component in the field. Such an approach ties up capital, storage space, and can cause some components to "expire" as they sit, unused, on a shelf in a warehouse. When leaks are found, sometimes new components or parts of components must be ordered. Depending on the item, this may take time to receive. Some components or parts might have to be made by the manufacturer or sub-contractor to the manufacturer of the leaking equipment if they are not in stock. Operators have little to no control on the supply chain, especially on rare to fail parts. Further, it should be obvious that supply chains can be disrupted by things outside the operator's control. Look no further than what a global pandemic did in 2020 and 2021. Operators must have the time needed to acquire replacement parts without penalty as long as they mark the item that has been identified as needing repair and repair it in a timely fashion once parts are available.

Q. DID NMOGA PROPOSE SOME CHANGES TO THE PROPOSAL TO ADDRESS THIS PROBLEM?

A. NMOGA has offered new language that allows an operator to tag the component in need of repair that cannot be repaired within 30 days of discovery as "Repair Delayed". The operator has an obligation to complete the repair within 15 days of receiving the component or part. This is a necessary flexibility that recognizes the urgency of needed repair with the realities of the market.

Q. DID YOU REVIEW ERG'S COST-PER-TON ANALYSIS COMMISSIONED BY NMED TO SUPPORT THE LEAK REPAIR THRESHOLDS AND FREQUENCIES IN 20.2.50.116.C(3)?

A. I did. You will find our analysis included in the comments in the NMOGA redline for your reference.

Q. WHAT ISSUES DID YOU IDENTIFY, IF ANY, REGARDING ERG'S ASSUMPTIONS ABOUT OPERATIONS IN NEW MEXICO?

A. In virtually all cases, the ERG cost-per-ton analysis that NMED used consistently and significantly understated the actual cost because it used data that was not representative of New Mexico producing sites in either the northwest or the southeast producing regions of the state. ERG analysis was based on a flawed assumption that OGI and EPA Method 21 equipment were used in equal measure in survey data. This led to inaccurate base level data which skewed their results. Further, the Model Plant used by EPA was not representative of either Permian Basin (southeast New Mexico) oil production sites or natural gas well sites typical of the San Juan Basin (northwest New Mexico).

Q. WHAT ISSUES DID YOU IDENTIFY, IF ANY, IN ERG'S COST-PER-TON ANALYSIS TO SUPPORT NMED'S PROPOSAL FOR WELL PRODUCTION FACILITIES?

A. These flaws in the ERG analysis led to inaccurate results when calculating the cost per ton of emissions reduction from LDAR. At well production facilities, as our comments in the redline make clear, when more appropriate data is used, the actual cost per ton is higher, and in many instances significantly higher, than what NMED relied upon. For example, for the cost per ton at oil well production facilities with GOR less than 300, the actual cost is almost triple the ERG estimate.

Q. WHAT ISSUES DID YOU IDENTIFY, IF ANY, IN ERG'S COST-PER-TON ANALYSIS FOR GATHERING AND BOOSTING SITES?

A. NMED analysis was based on old and outdated data in the form of another "Model Plant". Basing our estimate on more recent peer-reviewed studies yields a more reliable and appropriate estimate for the cost per ton of emissions reduction due to LDAR. Our comments in the redline illustrate those estimated costs on various frequencies of inspection. As you can see, the costs based on more accurate data are quite high and much higher than warranted.

Q. WHAT ISSUES DID YOU IDENTIFY, IF ANY, IN ERG'S COST-PER-TON ANALYSIS FOR TRANSMISSION COMPRESSOR STATIONS?

A. The ERG analysis did not even use data from actual transmission compressor stations. They used data from Gathering and Boosting Stations which handle unprocessed natural gas. This is a significant error in their assumption that led to incorrect results. Natural gas being handled at transmission compressor stations has already been processed to remove almost all heavier components (the VOCs) and therefore has virtually no potential to emit VOCs. By basing their analysis on unprocessed natural gas, their analysis cannot be expected to represent actual emissions or emissions reductions due to LDAR.

Q. WHAT ISSUES DID YOU IDENTIFY, IF ANY, IN ERG'S COST-PER-TON ANALYSIS FOR GAS PLANTS?

A. The ERG analysis errs in its basis for calculating the cost per ton of emission reduction for gas processing plants. They also incorrectly assumed that the costs for certain federally required LDAR programs can be ignored. These flaws, and perhaps others, left the NMED with incomplete analysis on which to base the proposed rule. NMOGA's recommendations for LDAR at gas processing plant recognize more directly the complexity caused by various federally required programs, and therefore a more robust analysis is utilized to base recommendations for change.

Q. BASED ON THE ISSUES YOU HAVE IDENTIFIED, WHAT LEAK RATE THRESHOLDS AND FREQUENCIES DO YOU RECOMMEND?

A. NMOGA has recommended both leak rate thresholds and inspection frequencies for all major facilities as outlined in the redline including well production facilities, gathering and boosting stations, and transmission compressor stations. These parameters result in significant VOC reductions and a much more reasonable cost per ton than that offered by NEMD based on the flawed ERG analysis.

PROPOSED 20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING

Q. DO ALL LIQUID UNLOADING OPERATIONS VENT GAS TO THE ATMOSPHERE?

A. Gas well liquid unloading is a complex process that is customized to wells according to their particular characteristics. It is in the best interest of the operator of a gas well that is in need of unloading liquids to not lose any gas to the atmosphere. The operator's livelihood is selling gas, not emitting it. Sometimes a well can be manually unloaded by shutting it in to build pressure and then opening it to the facilities and sales. Other times, substances like foamers can be introduced into the well in order to assist the well's ability to lift the liquids to the surface facilities while staying online and maximizing sales. Only when these types of techniques are not effective, liquid unloading to a lower backpressure by venting to the atmosphere may be the best alternative to restoring production.

Q. SHOULD THESE REGULATIONS BE LIMITED TO JUST THOSE ACTIVITIES THAT VENT TO THE ATMOSPHERE?

A. NMOGA has suggested modifications to this rule to recognize that only those manual liquid unloading events that result in venting of gas to the atmosphere are covered by this section of the rule. Since only manual liquid unloading involving venting to the atmosphere would result in emissions, it is just common sense that there is no benefit to emissions reduction to apply them to activities that do not cause emissions.

Q. DID NMOGA PROPOSE CHANGES TO ACCOMPLISH THIS?

A. Yes, see the first sentence in the applicability paragraph of this section.

Q. WHAT ARE AUTOMATED CONTROL SYSTEMS AND HOW DO THEY REDUCE VOC EMISSIONS?

A. Just as NMED has stated in their suggested best practices in paragraph 117.B.2.c, closing the vent valve as soon as practical after an unloading event will help minimize venting volumes. Depending on an individual well's producing characteristics, an automatic controller can detect certain parameters signaling that an unloading event has reached an end point and respond by actuating a valve to send gas back to the facilities and sales. This could mean detecting the arrival of a plunger, or a change in other operating parameters such as flowline pressure. Technology in this space has advanced over time so we might expect new ideas to be developed that would fit under this language.

Q. SHOULD THESE BE INCLUDED AS AN ADDITIONAL MANAGEMENT PROCEDURE?

A. Yes, Allowing liquid unloading to the atmosphere to occur as long as automated control system is installed and operating as one of the methodology options will encourage the deployment of these "smart" systems now and as they may be developed in the future. Even those systems that exist today can be deployed to make gas well liquid unloading more effective and vent a lower volume of natural gas. NMED should allow this additional methodology to their list in 20.2.50.117.B.3.

PROPOSED 20.2.50.120 HYDROCARBON LIQUID TRANSFERS

Q. AS AN OIL INDUSTRY OFFICIAL, CAN YOU TELL FROM THE PROPOSED RULE WHETHER PRODUCED WATER IS INCLUDED IN THE SCOPE OF HYDROCARBON LIQUID TRANSFER AS PROPOSED?

A. There is unclear in the original language whether the hydrocarbon liquid transfer requirements apply to the transfer of produced water. NMOGA offers modifications to make it clear that requirements for hydrocarbon liquid transfers found in 20.3.50.120 do not apply to the transfer of produced water.

Q. WHY IS IT A SUBSTANTIAL PROBLEM IF PRODUCED WATER IS INCLUDED IN THIS PROPOSED SECTION?

A. NMOGA supports the added requirements for minimizing VOC emissions associated with some hydrocarbon unloading events. This would include requiring vapor balancing or vapor capture to a control device. This can be accomplished because of the way oil tanker trucks are designed. These trucks typically have liquid pumps on the truck to facilitate oil, condensate, or intermediate hydrocarbon liquids at a prescribed rate. Vapors in the tank that are displaced by liquids being loaded can be routed back to the source tank (vapor balancing) or routed to a control device for destruction. If modified to explicitly exclude produced water, these requirements are cost effective on a $/emission volume basis. Water hauling trucks are designed in a very different way as they may be used to suck water from pits or other sources that are below the level of the tank itself. Many times these liquids contain solids like sand that would damage liquid pumps so these trucks are equipped with vacuum pumps that allow liquids to be vacuumed into the tank rather than being pumped. Because of this, the rate at which gasses (air, hydrocarbon vapors, etc.) are expelled from the tank as it is loading is much higher than can be managed in a vapor balancing process as it would likely damage the storage tank if that were attempted (tanks can withstand very little pressure or vacuum before they are damaged). Sending gasses from the tank to a control device would introduce a serious safety concern as it likely contains oxygen, which could cause an explosion. NMOGA has suggested modifications to this section and to associated definitions to ensure that it is clear that these new requirements do not apply to produced water transfers.

Q. DO WELL PRODUCTION FACILITIES AND THEIR ASSOCIATED TANK BATTERIES THAT DELIVER LIQUIDS DIRECTLY TO PIPELINES HAVE SIGNIFICANT HYDROCARBON LIQUID TRANSFERS?

A. No. As NMOGA supports these new requirements in general, we recognize that there are certain circumstances where the cost to capture vapors associated with hydrocarbon liquid transfer would be economically impractical. Such is the case where a well production facility is connected to and utilizes an oil pipeline for routine oil sales. Oil pipelines are typically very reliable so any such facility would only engage in truck loading on very rare occasions. VOC emissions associated with these rare truck loading events would be small indeed, perhaps zero for years at a time.

Q. BECAUSE HYDROCARBON LIQUID TRANSFER IS LIMITED TO JUST PERIODS OF PIPELINE OUTAGE OR MAINTENANCE, TECHNICALLY AND ECONOMICALLY REASONABLE TO IMPOSE THESE EQUIPMENT STANDARDS ON SUCH FACILITIES?

A. Requiring such facilities to install vapor balancing or capture equipment would cause the cost of emissions reduction to be extremely high on a $/volume of emissions basis and NMOGA urges NMED to make the changes suggested to not require vapor balance or capture for control on tank batteries that are connected to active oil pipelines.

Q. BESIDES FACILITIES THAT ARE CONNECTED TO OIL PIPELINES, ARE THERE OTHER SITUATIONS WHERE HYDROCARBON LIQUIDS TRANSFERS REPRESENT RELATIVELY SMALL EMISSIONS?

A. Emissions associated with hydrocarbon liquids transfer are a function of the frequency of such transfer events. There are some wells in New Mexico that produce very low liquid hydrocarbon rates. When these wells are connected to facilities that then collect very low liquid hydrocarbon rates, then liquid loadouts are themselves infrequent. Installing vapor balancing or vapor capture to control equipment on such wells would result in extremely high cost on a $/emissions volume basis and is economically impractical. NMOGA recommends that the requirement for vapor balance or vapor capture be applicable only to wells/facilities that load out hydrocarbon liquids more than 12 times per calendar year.

Q. ARE BOTTOM LOADING AND/OR SUBMERGED FILL HELPFUL IF THE LOADING OPERATION IS VAPOR BALANCED OR ROUTED TO A CONTROL DEVICE?

A Vapor balance and vapor capture to a control device are not affected by whether a tank is designed for bottom fill. Further, operators of facilities being served by a third-party oil hauler do not have access to tank specifications so should not be held accountable for transfer tank design.

Q. IS IT FEASIBLE FOR THE OWNER/OPERATOR TO INSPECT EVERY HYDROCARBON LIQUID TRANSFER? WHY OR WHY NOT?

A. Most well production facilities are unmanned. The transfers of hydrocarbon liquids occur at all hours of the day and night with little notice as to exactly when the tanker truck is arriving so there is significant operational burden in requiring operators to travel sometimes very long distances to witness loading events on a regular basis. NMOGA has suggested that loading events can be witnessed once per month on manned locations and twice a year on unmanned sites so that vapor balancing or capture equipment can be inspected while in use.

Q. DO THE OIL COMPANY OPERATORS USUALLY “OWN” OR “OPERATE” THE TANK TRUCKS AND RAIL CARS?

A. No. In almost every case, these tank trucks or rail cars are owned by companies other than the owner of the well production facility.

Q. WOULD OPERATORS HAVE DIRECT ACCESS TO SUCH RECORDS OR WOULD THE COMPANIES OWNING THOSE VEHICLES HAVE SUCH RECORDS?

A. Operators typically do not have access to the testing records of the trucks that service their facilities if owned by third parties. Those records are kept by the owner of the truck as they must adhere to certain test requirements of other agencies. There is no certainty that truck owners would grant access to these records on any basis.

PROPOSED 20.2.50.121 PIG LAUNCHING AND RECEIVING

Q. DOES NMOGA HAVE CONCERNS REGARDING NMED’S PROPOSED REGULATIONS AFFECTING PIG LAUNCHING? WHAT ARE THEY AND WHY?

A. Emissions from pigging operations on gas pipelines are a very small contributor of VOCs. To require that such emissions be combusted can be extremely expensive on a $/emissions volume basis. When such pigging activities occur at a well production facility or at a Gathering and Boosting Station or at a gas processing plant, the small emissions can more practically be captured and routed to a control device. When such pigging operations occur away from these more centralized sites and at remote sites in the field, the operational challenges and attendant costs become impractical. Couple this with the idea that air modeling indicates that areas of ozone concern are often NOx limited, the imposition of requirements to combust pigging emissions at remote sites results in extremely high cost to convert VOCs to NOx and may increase ozone formation. NMOGA’s recommends that NMED modify language in this section to only require capture and control of emissions related to pigging operations at well production facilities, gathering and boosting stations, and gas processing plants.

PROPOSED 20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS

Q. AS A FORMER OIL INDUSTRY OPERATING OFFICIAL, IS IT FEASIBLE TO REMOVE ALL PNEUMATIC CONTROLLERS FROM TEMPORARY PUMPS, SUCH AS THOSE THAT REMAIN ON SITE FOR LESS THAN 90 DAYS?

A. No. First, most such pumps and other equipment that might be operated with pneumatic devices are rented, third party equipment. Second, there is no practical way for such equipment to be operated without utilizing pressurized natural gas since, in most cases when such equipment is used, permanent facilities are either not constructed yet or are on a remote pad. It is highly impractical to require something other than natural gas operated pneumatics devices in these situations.

Q. AS A FORMER OIL INDUSTRY OPERATING OFFICIAL, DOES IT MAKE MORE SENSE TO PHASE OUT NON-ESSENTIAL PNEUMATIC CONTROLLERS ON A CONTROLLER COUNT OR A PERCENTAGE OF PRODUCTION BASIS? WHY?

A. Basing phase out on a production basis for Well Production Facilities will result in better results all around. For NMED, it will speed up emissions reduction and make enforcement more transparent. This plan will speed emissions reduction because it will focus activity on the largest producing sites first. The biggest producing sites are a good place to start because there are typically many pneumatic devices at these sites and the sites are more likely to have utility electric power so compressed air systems can be more easily installed to drive the devices. This also makes sense for operators since these sites are the most cost effective to transition to non-emitting devices (even if utility power is not available). Also, when coupled with the new OCD Waste Rule and other provisions in this rule, inspections of all sites will be increased so the incident of malfunctioning pneumatic devices will likely be reduced. The OCD rule requires weekly documented AVO inspections on most sites and this rule will likely increase LDAR on most sites so malfunctioning pneumatics will be discovered more quickly everywhere. And finally, basing a replacement schedule on a percentage of production basis at well production facilities will be transparent since production is already reported to OCD and will be a public record and, perhaps most helpful, the plan will result in entire sites being either non-emitting or emitting which should make monitoring and enforcement much easier for NMED.

Q. DID COLORADO ADOPT THIS APPROACH AFTER AN EXTENSIVE PROCESS WITH ENVIRONMENTAL, INDUSTRY AND REGULATOR INPUT?

A. Yes, because it just makes sense for both operators and emissions reduction.

Q. HAS NMOGA PROVIDED A REDLINE ADOPTING THIS COLORADO APPROACH FOR THE BOARD'S CONSIDERATION.

A. Yes. We worked with the structure that NMED proposed but changed the schedule to be based on a percent of production and introduced the concept of emitting and non-emitting sites.

Q. IS IT APPROPRIATE TO USE THE "CONTROLLER COUNT" METHOD FOR DETERMINING PHASE OUT AT GATHERING AND BOOSTING SITES AND NATURAL GAS PROCESSING PLANTS?

A. There is a much lower number of gathering and boosting sites and even fewer gas processing plants These gas processing plants tend to have a large number of pneumatic devices. Clearly as gas is gathered from many sources, the highest gas volumes being handled in such systems will be at the processing plants. This skews the numbers such that designing a replacement schedule on a gas volume basis (the same basis as well production facilities) would require an unreasonably rapid replacement schedule for operators of gas processing plants. NMOGA recommends retaining the device count basis for transition away from emitting devices on gathering and boosting stations and gas processing plants.

Q. WHY ARE SOME CONTROLLERS "NECESSARY FOR A SAFETY OR PROCESS PURPOSE" EXEMPTED UNDER THE FEDERAL AND COLORADO RULES?

A. There are some end devices, like large, quick-acting valves, that require responses that only high-bleed devices can offer. Such devices should be allowed to be exempted from requirements to change to non-emitting. This rule allows for that as long as operators notify NMED of such need and support the need with data.

Q. AS A FORMER OIL OPERATING OFFICIAL, IS THIS EXEMPTION NECESSARY IN NEW MEXICO AS WELL?

A. This exemption should be allowed anywhere as long as they are supported by the data to provide a safe work environment.

Q. IS THERE ANY REASON TO LIMIT USE OF INSTRUMENT AIR OR INERT GAS?

A. No. These driving gasses are not ozone precursors. There should not be any limits on such uses.

Q. CAN ALL THE DIAPHRAGM PUMPS BE UPGRADED OR REPLACED IMMEDIATELY OR IS SOME TIME NEEDED TO UPGRADE OR REPLACE THEM?

A. As with most equipment, human resource and supply chain limitations will not allow immediate replacement of all pneumatic pumps. NMOGA recommends allowing three years for operators to transition such pumps to non-emitting and then only if it is technically and economically feasible. Those instances where it is not technically or economically feasible, operators must demonstrate that to NMED for approval of an exemption.

PROPOSED 20.2.50.124 WELL WORKOVERS

Q. IN YOUR EXPERIENCE, DOES REQUIRING CERTIFIED MAIL FOR NOTICE ADVANCE ANY ENVIRONMENTAL INTEREST OR DOES IT HAMPER GIVING EFFECTIVE NOTICE?

A. Notifying residents within ¼ mile of a well before a workover will have no impact on emissions. Regardless of that, NMED has proposed that notification by certified mail be given to such residents. NMOGA understands that, regardless of the lack of emissions impact, giving notice to residents of planned well work that could have significant emissions, such as recompletions or hydraulic fracture stimulations, is reasonable and we support that provision. That same three-day, certified mail notice is <u>not</u> supported when routine well work that is not expected to generate significant emissions. Routine well work such as replacing a downhole pump, a tubing repair, a well clean-out and the like does not create significant emissions and to require the same, slow notice would be very disruptive of efficient use of workover rigs and other equipment. There are so many new methods to communicate today that are easier and more transparent than using certified mail. NMOGA recommends that operators be required to give notice 24 hours in advance of starting such routine well work using any method that can be documented so that NMED could be given proof of notice if required.

PROPOSED 20.2.50.125 SMALL BUSINESES

Q. AS A STAFF LEADER OF THE LARGEST NEW MEXICO OIL AND GAS TRADE ASSOCIATION, ARE YOU AWARE OF ANY OIL AND GAS OPERATOR, WHETHER A MEMBER OF YOUR ASSOCIATION OR NOT, WHO WOULD QUALIFY UNDER THIS PROVISION?

A. No. We have looked at the data provided by NMED for this process and have inquired of members and do not believe that any oil and gas operator would qualify. This means that there are no exceptions to this rule, no matter how small your business or how expensive the emission reduction might be. The result is that this rule, as written will have a devastating impact on many small businesses in the state. NMOGA estimates that 87% of all gas wells (virtually all of the moderate and low production rate gas wells) will not be able to justify the required compliance costs and operators will be forced to shut them in. (We will offer expert testimony on that analysis.) Many businesses that own and operate these wells will suddenly find themselves with virtually no income and will be forced to go out of business leaving their owners and employees without an income. This result will be especially impactful to our neighbors in the northwest part of the state since long life, low volume gas wells are common in that region. These devastating consequences are not necessary. New rules from the OCD Waste Rule and carefully crafted requirements in this rule can ensure that these valuable, but low rate gas wells can remain on production with reduced ozone precursor emissions. NMOGA has carefully considered how to apply each and every section of this proposed rule such that emissions are significantly reduced with a reasonable burden on the industry. We urge the EIB to adopt the more balanced approach offered by this important industry. Know that, under a rule as modified by NMOGA, no operator will be exempt from this rule but requirements for emissions reduction will be applied where they make economic sense and will result in significant ozone precursor emission reduction.

PROPOSED 20.2.50.126 PRODUCED WATER MANAGEMENT UNITS

Q. IN YOUR POSITION AS SENIOR ADVISOR AND YOUR PAST POSITION AS AN EXECUTIVE AT AN OIL AND GAS OPERATOR, DO YOU HAVE CONCERNS REGARDING THE PROPOSED REQUIREMENTS FOR PRODUCED WATER MANAGEMENT UNITS? IF SO, WHY?

A. I am proud of the progress that the oil and gas industry in New Mexico has made to reduce its use of fresh water in our well construction operations. The company where I was employed before joining NMOGA was a leader in transitioning to the use of produced water for hydraulic fracture stimulations and, by the end of 2013 was using mostly produced water. The industry as a whole has moved <u>voluntarily</u> from what was likely nearly 100% fresh water 10 years ago to less than 10% fresh water today. This is an environmental victory aided by legislation and now documented by the OCD through their new reporting requirements in Frac Focus. The requirements as proposed by NMED could inadvertently reverse that progress and as someone who has supported responsible operations in the oil and gas industry, I am strongly against these requirements as drafted by NMED. NMOGA has offered modifications to this rule that will allow NMED to better manage emissions from these facilities while not reversing all of the progress of the last decade. We will also offer a technical expert in the area of emissions from water management units to give the EIB a better understanding of the issue and why NMED's proposed regulation could cause increased fresh water consumption.

<u>PROPOSED 202.50.127 PROHIBITED ACTIVITY AND CREDIBLE INFORMATION PRESUMPTION</u>

Q. DO YOU BELIEVE THAT SUBSECTIONS B AND C OF PROPOSED 20.2.50.127 WILL IMPROVE ENFORCEMENT AND COMPLIANCE IN NEW MEXICO? WHY OR WHY NOT?

A. Without proper protocols on providing credible evidence, this rule will encourage untrained citizens to file complaints and accusations of violations that, as written, will be accepted as proof of violation. This would be unfair to operators and would tie up NMED resources pursuing enforcement without sufficient justification and shifting the burden of proof of innocence on the operator.

Q. HAS NMOGA PROPOSED REDLINES TO ADDRESS THE MOST EGGREGIOUS ASPECTS OF THIS PROPOSED SECTION?

A. Yes. NMOGA recognizes that valid citizen complaints should be investigated and, if found to be supported by credible evidence, pursued by gathering evidence from the accused operator, and only then as a violation <u>if</u> the balance of evidence supports such action.

By: <u>/s/ John Smitherman</u>
John Smitherman

Appendix A2 – Direct Testimony of Adam Meyer

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION
20.2.50 **No. EIB 21-27 (R)**
Oil and Gas Sector – Ozone Precursor Pollutants

TESTIMONY OF ADAM MEYER

PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. Adam Meyer, 3755 Dudley Street, Wheatridge, CO 80033

Q. WHAT IS YOUR INVOLVEMENT IN THIS PROCEEDING?

A. I am leading the Valor team to provide technical expertise in support of NMOGA in this rulemaking. I am personally providing technical expertise on subject of Storage Vessels and associated Hydrocarbon Loadout as it pertains to the Valor memos and system design, and Pneumatic Controllers as it pertains to the Valor memos.

Q. WHAT IS YOUR OCCUPATION?

A. I am the Vice President of US Operations at Valor EPC.

Q. HOW LONG HAVE YOU HELD YOUR CURRENT POSITION?

A. Three months.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I received by Bachelor's of Science in Mechanical Engineering from the Pennsylvania State University, and Master's of Science in Mechanical Engineering Thermal Fluid Transport from the University of Florida.

Q. PLEASE BRIEFLY SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. After undergraduate school, I worked as an engineer for Electric Boat in Groton Connecticut in the design and construction of submarine fluid systems. Then I worked as a reliability engineer and then a thermal and fluid systems engineer for United Space Alliance in Cape Canaveral Florida on the Space Shuttle Program for cryogenic systems, hypergolic fluid systems, and gaseous systems. After the Shuttle Program, I was an auxiliaries and controls engineer for Siemens in Orlando Florida analyzing, engineering, and designing balance of plant systems for gas turbine power generation plants. And for the past seven years, I have been working in oil and gas based out of Denver for ZAP Engineering and now Valor EPC in the engineering and design of upstream production facilities, compressor stations, and other facilities in other industries. My specialty over the past seven years as it pertains to this rulemaking is storage tank close vent system analysis and design.

Q. WHAT ARE YOUR PROFESSIONAL AFFILIATIONS, IF ANY?

A. None

Q. WHAT HAVE YOU BEEN ASKED TO ADDRESS IN YOUR TESTIMONY BEFORE THE BOARD?

A. I was asked by NMOGA to coordinate assessment of certain areas of the New Mexico ozone rules in which Valor EPC personnel have expertise. I was asked by NMOGA to address the activities of the Valor EPC team, and to personally address the subject of storage tanks and hydrocarbon loadout.

Q. HAVE YOU PREPARED TECHNICAL REPORTS ON THESE ISSUES?

A. Yes.

Q. PLEASE LIST THE TECHNICAL REPORTS THAT YOU HAVE PREPARED.

A. "Valor Memo – Storage Vessels 20.2.50.123", "Valor Memo – Pneumatic Controllers 20.2.50.122 Emission Factors", and "Valor Memo – Pneumatic Controllers 20.2.50.122"

Q. DO YOU ADOPT THESE TECHNICAL REPORTS AS YOUR DIRECT TESTIMONY BEFORE THE NEW MEXICO ENVIRONMENTAL IMPROVEMENT BOARD?

A. Yes

Q. ARE THESE TECHNICAL REPORTS ATTACHED?

A. Yes

By: /s/ Adam Meyer
Adam Meyer

Date 7/28/21
New Mexico Oil and Gas Association
Attn: John Smitherman

SUBJECT: Valor EPC Study: NMAC 20.2.50.123, Storage Vessels

Dear Mr. Smitherman,

Valor EPC is pleased to provide this study and supporting evidence on the subject of Storage Vessels in response to the proposed rules to Title 20 Chapter 2 Part 50 (20.2.50 NMAC) paragraph 20.2.50.123. The below study represents Valor EPC's professional opinion based on years of experience and supporting data, to the maximum extent possible, within the schedule required.

Executive Summary

Valor EPC has reviewed NMED's "Storage Tank Reductions and Costs VOC 6-2-2021" Excel sheet and determined that it assumes a small control device will be required for tank vapor handling, and omits costs associated with vapor capture during liquid loading especially if produced water is classified as a "hydrocarbon liquid" per the current definition in NMAC rule 20.2.50.123. Furthermore, single/tank batteries could have a larger cost to barrelage impact that Valor EPC considers unreasonable. As such, the impact of the proposed rule will result in significant costs to the industry, more than projected by ERG and NMED. Valor EPC suggests that NMOGA propose revisions to the applicability and emissions standards for this part as follows:

1) Existing single/standalone storage vessel tank batteries and multiple storage vessel tank batteries with an individual tank uncontrolled potential to emit (PTE) equal to or greater than 6 tpy of volatile organic compounds (VOC). By Valor's estimation, changing to 6 tpy applicability could achieve 70% of the VOC reduction goal for 1/3 of the cost.
2) New single/standalone storage vessel tank batteries and multiple storage vessel tank batteries with an individual tank uncontrolled PTE equal to or greater than 2 tpy of VOC.
3) Drop produced water from the definition of "hydrocarbon liquid" as vapor capture during water truck loadout is cost prohibitive.
4) When a closed vent system (CVS) analysis is required for a tank system, there should be options to the operator for CVS analysis such as (a) theoretical modeling with a more reasonable approach other than modeling of the peak potential instantaneous vapor flowrate (PPIFVR), or (b) alternative methods such the assessment of the proper functionality of a closed loop control or advanced tank pressure monitoring system.

1 Process

Valor's goal was to evaluate the proposed rules to determine impact of implementation in terms of cost and emission reduction. Valor conducted this review as follows:

1) The first step was to review the data provided by ERG in the excel sheet called "Storage Tank Reductions and Costs VOC 6-2-2021" and data from the Greenhouse Gas Reporting (GHGRP) database, to determine the scope of facilities. Valor focused on the tanks and tank batteries currently uncontrolled.
2) The second step was to use Valor's experience in storage tank CVS design to determine the type of equipment that is likely needed at these sites to comply with the rule if a theoretical CVS analysis were to be performed using the methodologies accepted by EPA in past consent decrees.
3) The third step was to provide equipment and installation costs that reflect Valor's experience in implementation.
4) The fourth step was to extrapolate the costs to all tanks and tank batteries in the subject counties of New Mexico.
5) The last step was for Valor to propose an alternative that would not only reduce emissions but would have a lower cost impact to the industry.

2 Affected Facilities and Tanks

2.1 ERG Data

The scope of the tanks and tank batteries per the ERG data ("Storage Tank Reductions and Costs VOC 6-2-2021") is as follows:

- 1182 facilities with tanks
- 3921 tanks or tank batteries (some single entries have multiple tanks)
  - 1862 tanks or tank batteries being controlled, whose efficiency will need to be verified as compliant to the new rule (i.e., 95% or 98%).
  - 2059 tanks or tank batteries classified as "Uncontrolled", "Misc Control", or "Scrubber" and are unregulated by New Source Performance Standard (NSPS) Subpart OOOOa, and 1040 tanks or tank batteries that will need to reduce tank emissions by 95% or 98% with new rules.
    - 2 entries are truck loading vapors specifically.
    - 187 multiple tank batteries classified as "Uncontrolled", "Misc Control", or "Scrubber"
      - 52 tank batteries less than 2 tpy – 46.8 tpy total
      - 93 tank batteries greater than or equal to 2 tpy, less than 10 tpy – 419 tpy total
      - 42 tank batteries greater than or equal to 10 tpy – 971 tpy
    - 1870 single tanks classified as "Uncontrolled", "Misc Control", or "Scrubber"
      - 967 single tanks less than 2 tpy – 918 tpy total
      - 744 single tanks greater than or equal to 2 tpy, less than 10 tpy – 3114 tpy total
      - 159 single tanks greater than or equal to 10 tpy – 4312 tpy total

Emission Reduction for the Uncontrolled Tank Batteries:

.95*419 + .98*971 + 3114*.95 + 4312*.98 = 8533 tpy VOC

Total multiple tank batteries and single tank batteries >2 tpy required to be modified:

93+42+744+159 = 1038

2.2 GHGRP Data

Valor suspects that the NMED/ERG excel workbook "Storage Tank Reductions and Costs VOC 6-2-2021") only considers tanks the department has a record of in permitting files. Based on tanks reported into the Greenhouse Gas Reporting Program for 2019 (latest data available) by New Mexico operators, Valor suspects there are many more tanks that NMED/ERG has not considered. The following data was provided to Valor by Earth Science Systems in support of this memo:

Table 1. Small Tanks with <10 bpd throughput, Scaled Up NM - Production Segment

	Small Tanks wo/flare	Small Tanks w/flare	Small Tanks Total
Permian	3,995	772	4,767
San Juan	10,600	45	10,645

Table 2. Small Tanks with <10 bpd throughput, Scaled Up NM Gathering & Boosting Segment

	Small Tanks wo/flare	Small Tanks w/flare	Small Tanks Total
Permian	662	47	709
San Juan	221	0	221

Table 3. Large Tanks with >= 10 bpd throughput, Scaled up NM - Production Segment

	Large Tanks venting	Large Tanks w/flare	Large Tanks w/VRU
Permian	3,122	7,911	3,444
San Juan	366	319	93

Table 4. Large Tanks with >= 10 bpd throughput, Scaled up NM - Gathering & Boosting Segment

	Large Tanks venting	Large Tanks w/flare	Large Tanks w/VRU
Permian	437	682	840
San Juan	56	19	2

Total uncontrolled tank batteries: 19,459

It is unknown how many of these tanks are single/standalone tanks or part of a multi-tank battery. In addition, the VOC tpy data for these tanks is not available. However, if we extrapolate the known information from NMED/ERG (approximately 9% uncontrolled multi-tank batteries, and 91% uncontrolled single/standalone tank batteries), we can assume the following:

Estimated uncontrolled multiple tank batteries: 1,751
Estimated uncontrolled single tank batteries: 17,708

Similarly, if we extrapolate the known VOC uncontrolled PTE information from NMED/ERG (approximately 50% of tanks are less than 2 tpy VOC uncontrolled PTE, and 50% are over 2 tpy VOC uncontrolled PTE), we can assume the following:

Estimated number of tanks with less than 2 tpy VOC uncontrolled: 9640
Estimated number of tanks with greater than 2 tpy VOC uncontrolled: 9819

3 Required Equipment at Affected Sites

The second step of the process was to determine the equipment that will likely be required at these sites to comply with the rule. The size of the equipment is determined typically by performing a storage tank CVS analysis or assessment using methodologies and assumptions accepted by EPA.

3.1 Overview of Storage Tank Closed Vent System Analysis

To know what size CVS and control device is needed, several factors are considered and evaluated in a CVS analysis to prove that tank pressures do not reach the thief hatch or relief device set point under normal operations. The preferred method by EPA is to perform a steady state or dynamic storage tank analysis, that theoretically evaluates flash vapors, working vapors, and thermal/breathing vapors entering or being created by the tank battery and the frequency and duration of flash vapors, working vapors, and thermal/breathing vapors. In this theoretical CVS analysis, pressure in the tank is modeled by considering these inputs as well as the vapor space in the tanks and the takeaway capacity of the CVS (and associated control devices), all combined into a dynamic analysis. If the modeled tank pressure is less than the thief hatch relief point, then typically it is said that the CVS is adequately sized.

Other analysis methods, such has a performance assessment of closed loop control system, have been adopted in some consent decrees in place of theoretical modeling, however the costing portions of this memo Valor will assess the impact of CVS analysis using theoretical modeling and the associated methodologies and assumptions accepted by EPA.

3.2 Considerations for Control Device Sizing

3.2.1 Non-Precluded Inputs

Some EPA consent decrees have required that all closed vent systems be sized for all “non-precluded” inputs into the tank system to be modeled as simultaneously flowing into the tank system in order to find the peak potential instantaneous vapor flowrate (PPIVFR) through the CVS. Valor EPC adamantly disagrees with this practice as it can lead to overestimation of the PPIVFR which can lead to oversizing of equipment. Valor personnel have advocated for alternative CVS analysis methods to prove adequate capacity such as closed loop control systems (referred to as “the closed loop method”) and advanced tank pressure monitoring. Requiring a CVS analysis with a theoretical model and designing to a worst-case event (which includes calculation of PPVIFR by assuming all non-precluded inputs flow simultaneously) often leads to the installation of a larger CVS and control devices than would be reasonably expected.

3.2.2 Liquid Slugging

If a theoretical CVS analysis is used for sizing the CVS, liquid slugging into the tank should also be considered. Liquid slugging can cause momentary peak vapor rates through the CVS. In many cases, larger control devices or other modifications like orifice plates or chokes in the upstream system or tank liquid level control may be required to ensure that tank pressures do not exceed thief hatch pressure relief points.

3.2.3 Thermal/Breathing

Thermal/breathing of storage tanks refers to the vapors liberated from solution due to heating of tank liquids or the volumetric expansion of vapors residing in the vapor space. When tank liquids and gases are kept at a constant temperature (such as at high producing facilities or tanks with heaters), then thermal/breathing vapors can be assumed to be negligible. However, for lower producing sites, gases in the tanks cool in the evening and heat up in the morning (with the sunrise). Valor has found that using API 2000 outbreathing calculations best ensures that the volumetric expansion of these vapors is considered when sizing of control devices. Per API 2000, oil tank relief devices and vapor control systems (by association) must be sized for 1 scf/h per 1 bbl of vapor space to account for the volumetric expansion of the gas. These thermal/breathing vapor rates must be added to the total PPIVFR when sizing the CVS and could result in a larger control device.

3.2.4 Low Pressure Tank Rating

When controlling tank vapors, the CVS and control device are sized to preclude venting (due to pressure) from thief hatches. The thief hatch is set to protect the tank from overpressurization. Usually, tanks built to API 12F are built to withstand 16 oz/in2 pressure in their vapor space however that is not always the case. Many legacy tanks and tanks smaller than 210 bbl are not rated for 16 oz/in2 pressure, and in many cases are rated of 8 oz/in2, 4 oz/in2, or even “ATM” per their nameplate (the latter meaning that they are rated for 0 psig internal pressure). For the tanks rated for “ATM” (i.e., 0 oz/in2), in order to route the vapors to a CVS, the tanks will need to be replaced or rerated. For tanks rated for 8 oz/in2, tank pressure control can be difficult and usually means that the CVS and control device capacity needs to be nearly double when compared to a 16 oz/in2 tank. Below is an example of an “ATM” rated tank, that would need replacement under the new NMAC rules.

Figure 1. Example of condensate storage tank that would need replacement under new rules.

3.2.5 Truck Loadout Vapors

If truck loadout vapors are to be captured from oil and condensate truck activities, the easiest approach is to vapor balance the truck vapors with the tank battery. The vapors liberated from solution due to agitation (i.e., working vapors) can be estimated at 6 scf/bbl per API 2000 and should be considered when sizing the CVS and control device. As an example, loadout for oil/condensate is typically around 180 bbls loaded in 20-30 minutes. In this case, the tank CVS and control device would need to be sized for this additional duty: 300 gpm with 6 scf/bbl (agitation vapors only) would be 61 MSCFD for 20-30 minutes.

Capturing vapors from water trucks is more difficult to accomplish. Water truck vapors can be comprised of air or an unknown composition of gases and vapors. In addition, the process typically utilizes a truck mounted vacuum pump (e.g., Fruitland 500 LSH series) that initially ejects air/vapor mixture from the truck at a high rate (e.g., 330 to 400 cfm which is 475 MSCFD to 576 MSCFD instantaneous rate). When this occurs, a gas volume of air (or other unknown mixture of gases) is pushed into the tank vapor space. Not only is this a safety concern due to the oxygen, but the tank CVS and control device must accommodate for the huge instantaneous gas rate from the vacuum pumps. Vapors may need to be sent to a separate combustor or separate input to the same combustor (such as a separate burner rail) due to the unknown composition of the truck gas and the large gas flowrate.

3.2.6 Single Tank Batteries – Worst Hit by the Rules

In multiple-tank batteries with a lot of vapor space, pressure spikes are damped and are not as prevalent. Single/standalone tanks, however, can have the disadvantage of having little to no vapor space and may be prone to erratic pressure. Many solutions to "smooth out" the pressure in low vapor space tanks could include adding chokes or orifice plates in the upstream facility, adding intermediate stage separators upstream of the tanks, or using a larger CVS and control device. As such, there could be an even larger cost for single/stand-alone tanks relative to multiple tank batteries on a cost-to-barrelage basis. At compressor stations and gas plants, for example, there are often several small tanks distributed throughout the facility to catch drains from the facility equipment. Therefore, the cost is multiplied accordingly.

3.3 Control Devices Likely Required

With all the considerations described above and based on Valor's experience in CVS analysis, performing a theoretical CVS analysis with the PPIVFR and non-precluded inputs methodologies accepted by EPA will likely result in a larger combustor than is reasonably expected. Valor estimates that at least one 48" high volume combustor or 60" high volume combustor or a combination of smaller combustors used with additional intermediate separators, orifice plates/chokes, or any combination thereof would be required. The costs with adding a vapor recovery control unit are often uneconomical – even with larger tank batteries. As such, the remainder of this report will focus on installation of combustors at these sites.

Figure 2. Example of stand-alone condensate tank at a compressor station

Figure 3. Example of stand-alone condensate tank at a production facility

4 Equipment and Installation Costs

Combustor pricing provided in "Storage Tank Reductions and Costs VOC 6-2-2021", "Cost Factors" tab, Cell C6 appears to be based on pricing for a lower capacity combustor outfitted with burner management system, dual fuel train, etc. As described in the sections above, larger combustors, more combustors, or a combination of other modifications may be required at these sites. The following evaluates the size and flowrates of commercially available combustors. Costs are estimated based on older and new pricing as well as third hand pricing (i.e., equipment brokers).

Table 6. Combustor Size, Flows, and Pricing		
Size (diameter)	**Rated Flow (SG =1) MSCFD at 10 oz/in2 inlet**	**Pricing**
48" standard	23	$8,500 - $10,500
60"	49	$18,100 - $24,400
48" HVE (i.e., high volume)	107	$29,700
48" HVE dual rail	107 (max)	$57,019

As described in the sections above, there could be additional cost adders associated with truck loadout vapor control and the potential need for tank replacement (to achieve a higher tank rating). When combined, the cost per tpy VOC could be significantly higher. Valor estimates that the equipment cost proposed by NMED/ERG of $18,100 would be a minimum cost more so than an average cost.

Table 7. Valor Estimates for Tank Closed Vent System Upgrades				
Case	**Scenario**	**Hardware**	**Equip. Cost**	**Install. Cost**
Base Case	Combustor to prevent venting from hatches and relief devices from all non-precluded upstream inputs, flash vapors (simulated), working vapors (API 2000) and thermal/breathing (API 2000) assuming 16 oz/in2 tank(s)	60" or 48 HVE Combustor	$18,100-$29,700	[Baselined in "Storage Tank Reductions and Costs VOCS 6-2-2021"]
Adder 1	Tank Replacement (existing tank is "ATM" or low pressure rated)	300 or 400 bbl tank	+ $15,000 to $18,000	+$15,000 (estimated)
Adder 2	Oil truck vapor capture needed (additional 61 MSCFD combustion needed)	60" Combustor or 48 HVE or added capacity to primary combustor	+$18,100 to $29,700	+$7253 (from sheet)
Adder 3	Water truck vapor capture needed (replace use of vacuum pump with on-site pump to control loadout and send vapors to combustor added by "Adder 2")	Loadout Pump	+$5,200	+$10,000 (estimated)
		On Site Equipment Total (Low End):	$18,100	+$0
		On Site Equipment Total (High End):	$82,600	+$32,253

5 Cost Impact of the Rule

5.1 Update to ERG/NMED Cost Data

The costs proposed by NMED/ERG in "Storage Tank Reductions and Costs VOC 6-2-2021", "Cost Factors" tab, cell C12 show a total capital investment of $104,942 for 2019. However, Valor estimates that would be on the low end of the potential cost range based on the assessment in the above sections. Valor's capital investment estimate is shown in Table 8 below.

Table 8. Update to ERG/NMED Capital Investment Approximations

Capital Cost Items	2012$	2019$	Valor EPC 2021 Estimate$
Combustor	$18,169	$18,881	**$82,600**
Freight and Design	$1,648	$ 1,713	$ 1,713
Auto Ignitor	$1,648	$ 1,713	$ 1,713
Surveillance System	$ 3,805	$ 3,954	$ 3,954
Combustor Installation	$ 6,980	$ 7,253	**$ 14,507**
Storage Vessel Retrofit	$ 68,736	$ 71,429	**$ 96,429**
Total Capital Investment	**$100,986**	**$ 104,942**	**$200,915**

5.2 Update to Cost per ton of VOC

Updating "Storage Tank Reductions and Costs VOC 6-2-2021", "Cost Factors" tab, Cell C6 and C11 reveals the following:

1. Assuming 7% interest rate and term of 15 years: Cost per ton of VOC range is **$13,734 to $19,325** for the 2 tpy tank batteries.
2. Assuming 3.5% interest rate and term of 15 years: Cost per ton of VOC range is **$12,475 to $16,896** for the 2 tpy tank batteries.

5.3 Extrapolated Cost Impact

The current rule applicability threshold is 2 tpy VOC uncontrolled PTE, per tank. If we extrapolate the number of tanks presented in the NMED/ERG spreadsheet to the data provided in the GHGRP, and include the potential costs described above, the potential cost to the industry in New Mexico could be significant.

Table 9. Total Cost Impact for New Mexico

Uncontrolled Tank Count	Tanks Less than 2 tpy	Tanks greater than 2 tpy	Capital Investment Per	
			$104,942 per ERG	$200,915 per Valor
2057	1019	1038	**$108,929,796**	$208,549,770
19459	9640	9819	$1,030,464,220	**$1,972,858,519**

6 Conclusion

Valor has reviewed the cost estimates provided in "Storage Tank Reductions and Costs VOC 6-2-2021" and determined that it assumes a small control device will be required for tank vapor handling, and it omitted costs associated with possible tank replacement and vapor capture during liquid loading, especially if produced water is classified as a "hydrocarbon liquid" per the current definition in NMAC rule 20.2.50.123. However, Valor has shown that using EPA's accepted method of PPIVFR and non-precluded input assumptions, that a larger control device and associated systems will likely be required. In addition, the costs for implementation for single/standalone tanks at production facilities, compressor stations, and gathering and boosting sites is unreasonable. The number of affected uncontrolled tank batteries presented by ERG/NMED (i.e., 2057) is suspected to be a great underestimation, and overall, the costs associated with implementing this rule could be detrimental to the industry in New Mexico.

7 Rule Changes and Alternatives Proposed by Valor

As the rule is written, Valor believes there is a point of diminishing return. The changes to the proposed rule discussed below would accomplish substantial VOC reductions in a much more cost-effective manner. Valor's recommendations are as follows:

- The definition of Hydrocarbon Liquids needs to be modified to remove produced water as "hydrocarbon liquid" in the context of the rule. With produced water being considered a hydrocarbon liquid, produced water tanks will require truck vapor capture which may require an additional combustor or combustor burner rail just to accommodate for the unknown composition of the truck vapors. This aligns with Colorado rules that do not require truck vapor capture during produced water loadout.

- Vapor control during truck loadout should apply to oil and condensate tanks that have multiple loadouts per year. Vapor control during truck loadout should not apply to existing tanks that have twelve (12) or fewer loadouts in a year (once a month) or for future sites where truck loadout is a backup operation to pipeline pumps.

- The applicability threshold to control tank vapors from hydrocarbon tanks and produced water tanks should be 6 tpy VOC uncontrolled PTE for existing tanks. For new tank batteries, the threshold of 2 tpy VOC controlled PTE is reasonable. Valor recommends NMOG propose a higher applicability threshold for single/standalone tanks based on their expected and unreasonably high cost-to-barrelage.

- Control devices should be designed for 98% efficiency, however, overall control from a source should be 95% control. If overall control from a source is forced to 98% (per NMED's proposed rule), then the efficiency of the control device would need to be 100%, which is not reasonable and may be unachievable.

- Provide options for the CVS analysis other to include (a) theoretical modeling which may be performed (at the operators discretion) considering a reasonable number of simultaneously flowing inputs to the tank system (and remove any expectation of utilizing the EPA's accepted PPIVFR concept), (b) alternative methods such a closed loop control systems or advanced tank pressure monitoring systems. These options will ultimately lower the cost associated as it will prevent oversizing of the CVS and resolve known issues with control device turndown.

7.1 Affected Facilities and Tanks

7.1.1 ERG Data

If we apply the 6 tpy applicability to the NMED/ERG data, the emission reduction and number of affected sites are as follows:

- 1182 facilities with tanks
- 3921 tanks or tank batteries (some single entries have multiple tanks)
  - 1862 tanks or tank batteries being controlled, whose efficiency will need verification by new rule to 95% or 98%.
  - 2059 tanks or tank batteries classified as “Uncontrolled”, “Misc Control”, or “Scrubber” that will need to reduce tank emissions by 95% or 98% with new rules and are unregulated by NSPS OOOO/a
    - 2 entries are truck loading vapors specifically.
    - 187 multiple tank batteries classified as “Uncontrolled”, “Misc Control”, or “Scrubber”
      - 52 tank batteries less than 2 tpy – 46.8 tpy total
      - 74 tank batteries greater than or equal to 2 tpy, less than 6 tpy – 271 tpy total
      - **61 tank batteries greater than or equal to 6 tpy – 1119 tpy**
    - 1870 single tanks classified as “Uncontrolled”, “Misc Control”, or “Scrubber”
      - 967 single tanks less than 2 tpy – 918 tpy total
      - 635 single tanks greater than or equal to 2 tpy, less than 6 tpy – 2266.5 tpy total
      - **268 single tanks greater than or equal to 6 tpy – 5160 tpy total**

NEW REDUCTION: .95*1119 + .95*5160 = 5965 tpy VOC
Total existing multiple tank batteries and single tank batteries > 6 tpy: 61+268 = 329

7.1.2 GHGRP Data

Similarly, to what was done in previous sections, we can estimate the total number of tanks from the GHGRP data that are greater than or equal to 6 tpy (using ratio of 329/2057 * 19,459):

Estimated number of tanks with greater than 6 tpy VOC uncontrolled: 3,112

7.2 New Industry Cost Impact with Valor’s Proposed Rule

The total state cost projections with the proposed threshold at 6 tpy show 1/3 cost ($326M-$625M) compared to the current NMED rule. If produced water tanks do not require vapor capture during loadout and if single/standalone tanks receive different threshold applicability, the costs for implementation would be closer to $326M. If alternative CVS analyses such as closed loop control systems or advanced tank pressure monitoring system are allowed under the rule, the cost to the industry would be significantly less.

Table 10. Total Cost Impact for New Mexico

Uncontrolled Tank Count	Tanks greater than 6 tpy	Capital Investment Per	
		$104,942 per ERG	$200,915 per Valor
2057	329	**$34,525,918**	$66,101,035
19459	3112	$326,611,492	**$625,308,721**

7.3 VOC Emission Reduction Comparison

The ERG/NMED data shows that with adding controls to 1038 uncontrolled tank batteries then 8533 tpy VOC reduction can be achieved. Applying the 6 tpy applicability threshold to the ERG/NMED data, then only 329 tank batteries would need controls to achieve a similar and reasonable emission reduction of 5965 tpy VOC. When we extrapolate those emission reductions to the tank counts provided in the GHGRP data:

1. **Rule**: **9819** existing multiple storage vessel or single/standalone vessel tank batteries > 2 tpy, total of **80,718** tpy VOC reduction

2. **Valor Proposed:** **3112** existing multiple storage vessel tank batteries and single/standalone storage vessel tank batteries > 6 tpy, total of **56,422** tpy VOC reduction

This analysis shows that if the proposed rule is revised consistent with these recommendations, the final rule would still achieve substantial VOC reductions but in a more cost-effective manner for the industry. By Valor's estimation, changing to 6 tpy applicability could achieve 70% of the VOC reduction goal for 1/3 of the cost.

7.4 Nitrogen Oxide (NOX) Emissions

Valor has come to understand that New Mexico non-attainment is NOx limited. The analysis above addressed VOC emission reductions, which will likely be accomplished through combustion or flaring. Valor recommends that NMOGA communicate to NMED that combusting VOCs could increase NOx emissions for the state.

8 References

Applicable NMAC Paragraphs
NMAC 20.2.50.123
NMAC 20.2.50.120

Applicable NMED Documents
The following NMED documents were evaluated (reference https://www.env.nm.gov/air-quality/ozone-precursor-rule-hearing/)

1. Storage Tank Reductions and Costs VOC 6-2-2021

Reference Documents

1. Technical Support Document "2011 AND 2017 OIL AND GAS EMISSIONS INVENTORY DEVELOPMENT", 2016

Appendices
Appendix A – Vendor Datasheets and Quotes

We look forward to discussing this report with you in more detail.

Sincerely,

Adam T. Meyer
Principal, VP US Operations
Valor EPC | ph: 407.697.7289 | email: adam.meyer@valorepc.com

APPENDIX A – VENDOR DATASHEETS AND QUOTES

Item Pricing/Delivery				
Item	**Description**	**Qty**	**Price (Each)**	**Price (Total)**
1	Combustor -[redacted]CD - 60" Standard Vol	1	$18,100	$18,100
1 BMS	Profire 2100 Controller Standard Kit	1	$3,400	$3,400
1 BMS	Fuel Train: ECD Process & Safety Ctrl	1	$1,100	$1,100
1 BMS	Install BMS Components on Unit in Factory	1	$200	$200
1 BMS	Ship Loose: Valve, Butterfly 3in Hytork Act.	1	$1,200	$1,200
1 BMS	Profire Modbus Expansion Card	1	$400	$400
1	**Total Line Item 1 (Includes Selected Options)**	**1**	**$24,400**	**$24,400**
2	Combustor -[redacted]ECD - 48" High Volume	1	$23,400	$23,400
2 BMS	Profire 2100 Controller Standard Kit	1	$3,400	$3,400
2 BMS	Fuel Train: ECD Process & Safety Ctrl	1	$1,100	$1,100
2 BMS	Install BMS Components on Unit in Factory	1	$200	$200
2 BMS	Profire Modbus Expansion Card	1	$400	$400
2 BMS	Ship Loose: Valve, Butterfly 3in Hytork Act.	1	$1,200	$1,200
2	**Total Line Item 2 (Includes Selected Options)**	**1**	**$29,700**	**$29,700**

Item Pricing/Delivery				
Item	**Description**	**Qty**	**Price (Each)**	**Price (Total)**
1	ECD - 48" High Volume Truck Loading Combustor	1	$54,519	$54,519
1 BMS	[redacted]Controller w/ Remote BMS Module, BMS FW	1	Included	Included
2 BMS	[redacted]Solar Package 24VDC 180W	1	$2,200	$2,200
2 BMS	[redacted]Ignitor, Fuel Train, and Solar Kit Stand	1	$300	$300
1 BMS	Fuel Train: ECD Process & Safety Ctrl	1	Included	Included
1 BMS	Install BMS Components on Unit in Factory	1	Included	Included
1 BMS	ECD48HV: Inlet Piping with Low DP SDV	1	Included	Included
1	**Total Line Item 1 (Includes Selected Options)**	**1**	**$57,019**	**$57,019**

Description	Unit Price	Quantity	Line Total
Tank T-510, Oil Tank, 16 oz/in²	$ 15,992.00	1	$ 15,992.00
Tank T-520, Oil Tank, 16 oz/in²	$ 15,992.00	1	$ 15,992.00
Tank T-610, Water Tank, 16 oz/in² (insulation and heat trace up to 10' height) 1.75" fiberglass batt, corrugated aluminum sheathing with top flashing, SS banding heat trace: 8W/linear ft, two ciruits with termination kits, 120V supply	$ 22,186.00	1	$ 22,186.00
Tank T-620, Water Tank, 16 oz/in²	$ 15,992.00	1	$ 15,992.00

Reference #	Slsp	Terms	Whse	Freight	Ship Via
LOADING PUMPS	400	CHECK	04	PRE/ADD	PICK UP

Quoted By:	JEF	Quoted To:	ADAM MEYER	Effective:	08/02/2019	Expires:	10/15/2019

Item	Description	Ordered	UM	Price	UM	Extension
	WE OFFER THE FOLLOWING RATED FOR APPROXIMATELY 375 GPM AT 69 TDH TO CONSIST OF THE FOLLOWING:					
MCM 3X4X13	MCM 250 SERIES PUMP PUMP WITH IMPELLER TRIMMED TO 12.00' DIAMETER. CAST IRON PUMP WITH MECHANICAL SEAL, AND BACK UP PACKING. POWERED BY A 15 HP, 1200 RPM 3/60/230/460 VOLT TEFC ELECTRIC MOTOR, RATED FOR C1D2. COMPLETE WITH THREE PIECE SURE FLEX COUPLING, SHEET METAL COUPLING GUARD, AND ALL MOUNTED ON A COMMON STEEL CHANNEL BASEPLATE. NO CONTROL PANEL, MOTOR STARTER, OR VFD QUOTED.	1	EA	5201.00	EA	5201.00
	OPTIONAL PRICING IF PURCHASED IN 10 OR MORE QUANTITIES AT ONE TIME.					
MCM 3X4X13	MCM 250 SERIES PUMP PUMP WITH IMPELLER TRIMMED TO 12.00' DIAMETER. CAST IRON PUMP WITH MECHANICAL SEAL, AND BACK UP PACKING. POWERED BY A 15 HP, 1200 RPM 3/60/230/460 VOLT TEFC ELECTRIC MOTOR, RATED FOR	10	EA	4751.00	EA	47510.00

Date 7/28/21
New Mexico Oil and Gas Association
Attn: John Smitherman

SUBJECT: Valor EPC Study: NMAC 20.2.50.122, Pneumatic Controllers

Dear Mr. Smitherman,

Valor EPC is pleased to provide this study and supporting evidence on the subject of Pneumatic Controllers in response to the proposed rules to Title 20 Chapter 2 Part 50 (20.2.50 NMAC) paragraph 20.2.50.122. The below study represents Valor EPC's professional opinion based on years of experience and supporting data, to the maximum extent possible, within the schedule required.

Executive Summary

Valor EPC was asked by NMOGA to review NMAC 20.2.50.122 and supporting studies performed by New Mexico Environment (NMED) to quantify the cost to operators per ton of volatile organic compounds (VOC) or nitrous oxide (NOx) emissions so as to identify the cost effectiveness of the provision. For those requirements that are high cost on a per ton of emissions basis, Valor EPC has been asked to offer suggested modifications to the regulations, based on their experience, to improve cost effectiveness while preserving the impact on ozone precursor emissions.

Valor has reviewed the "Pneumatics Reductions and Costs VOC 5-27-2021" Excel sheet and concludes that the "Annual Cost per Site/Device" for Sites with Electricity and Sites without Electricity are not accurate or representative. Costs associated with equipment and infrastructure were greatly marginalized in ERG/NMED calculations. With current equipment costs and installation costs considered, Valor estimates costs ranging from $7,904/ton at sites with grid electric power already on site to a high of $23,829/ton on sites with no practical access to grid electric power.

1 Intermittent Device Emission Factor

Valor illustrated in a separate memo that the emission factor for intermittent control devices is outdated (see "Pneumatics Reductions and Costs VOC 5-27-2021", tab "Study Data", cell C124). The latest study data supports using 3.5 scf/hr in lieu of 13.5 scf/hr for estimated emissions from intermittent pneumatic devices. When the new factor is applied, the "Pneumatics Reductions and Costs VOC 5-27-2021", tab "Summary Pivot Tables", cell I29 changes from:

Annualized cost per ton VOC Reduced =

WAS: $2,745

w/Updated EF: **$7,213**

2 Conversion to Instrument Air (Site with Electricity On Site)

Valor has reviewed the ERG data related to conversion of facilities to instrument air and determined that the costs for conversion apparently used by NMED are significantly underestimated. Specifically, "Pneumatics Reductions and Costs VOC 5-27-2021", tab "Study Data", cell G59-G61. The basis for these estimates was prorated from Reference 1. Valor has found the costs for Instrument Air packages to be more expensive than provided in Reference 1 and "Pneumatics Reductions and Costs VOC 5-27-2021".

Standard upstream production facilities can use a range of air compressor units (i.e., 5, 15, 30 HP, etc) depending on number of end devices. The common theme from all installations is that the air compressor, dryer, and all electrical equipment need to be set, mounted, or housed and protected from the elements. This indicates that potential earthwork, concrete footing, or steel for skidded equipment or house framing will be required to set the air compressor and associated components. Buildings or sheds are often the best option for protection, but these may require structural engineering and design work to meet local building codes. The total cost of the building/housing/shed for the air compressor and associated system can be significant. Appendix A shows some examples of 5 HP ($42,240), 15 HP ($44,200 to $66,413), and 60 HP ($211,300, which includes price for a primary and redundant system) housed instrument air packages. If we assume that crane rental, electrical wiring, and total installation is 50% of the capital cost:

	Equipment and Installation	Total
5 HP	(42,240)*1.5	$63,360
15 HP	(44,200)*1.5	$66,300
60 HP	(211,300)*1.5	$316,950

When these costs are entered into "Pneumatics Reductions and Costs VOC 5-27-2021", tab "Study Data", cells G59-G61, the "Pneumatics Reductions and Costs VOC 5-27-2021", tab "Summary Pivot Tables", cell I29 changes as shown:

Annualized cost per ton VOC Reduced =

WAS:	$2,745
w/ Updated EF:	$7,213
w/Updated EF + Instrument Air Package Costs:	**$7,904**

3 Conversion to Instrument Air (Sites with Grid Access)

When it comes to facilities with no electricity on site, but access to grid power, the cost basis in Reference 1 and "Pneumatics Reductions and Costs VOC 5-27-2021" does not seem to consider infrastructure costs which may include:

1. Transformer or Pole-mounted transformer (Utility repaid by operator over time)
2. Electric meter (Utility repaid by operator over time)
3. Trenching and underground conduit run to the facility (Operator)
4. Terminations, junction boxes, grounding
5. Instrument Air Package

Utility meters and installation can be expensive (~$46,778), and the transformers are expensive and have very long lead times (8-12 weeks). Installation costs for cabling between the utility meter and the facility are estimated at $100-$150 ft. Overall, total costs are a minimum of $100,000. For the purposes of this memo, the instrument air building and the meter will be considered as the minimum required as there may be a transformer nearby already. Installation costs (piping, crane time, cabling and terminations) are estimated at 50% of the capital equipment costs. Therefore, the total approximate cost is:

	Equipment and Installation	Total
5 HP	(42,240 + 46,778)*1.5	$133,527
15 HP	(44,200 + 46,778)*1.5	$136,467
60 HP	(211,300 + 46,778)*1.5	$387,117

When these costs plus are entered into “Pneumatics Reductions and Costs VOC 5-27-2021”, tab “Study Data”, cells G59-G61, the “Pneumatics Reductions and Costs VOC 5-27-2021”, tab “Summary Pivot Tables”, cell I29 changes as shown:

Annualized cost per ton VOC Reduced =

WAS:	$2,745
w/ Updated EF:	$7,213
w/Updated EF + Instrument Air (+elec.) costs:	**$8,768**

4 Conversion to Instrument Air (Sites without Electricity)

For sites without electrical power or access to grid power, conversion to instrument air through solar power is best performed with a Generator/Solar/Instrument Air Compressor hybrid package. Pricing for these systems is provided in the Appendix and is $65,673 for a 5 HP unit, and $79,632 for a 15 HP unit. The pricing provided in the Appendix indicates that to add the solar panels would be an additional $12,447. This hybrid system provides functionality during times without sun and with sun and is critical for continued service of the facility. With installation costs included:

Unit	Cost Controllers, Valves, Pumps	Cost Supporting Equipment	Installation Cost Estimate (50% of capex)	Total
5 HP	$65,673	$12,447	$39,060	$117,180
15 HP	$79,632	$12,447	$46,039	$138,118

When these costs plus are entered into “Pneumatics Reductions and Costs VOC 5-27-2021”, tab “Study Data”, cell E110, F110, G110 respectively, the “Pneumatics Reductions and Costs VOC 5-27-2021”, tab “Summary Pivot Tables”, cell I29 changes as shown:

Annualized cost per ton VOC Reduced =

WAS:	$2,745
w/Updated EF:	$7,213
w/ Updated EF + Instrument Air (w/o elec) costs:	**$23,829**

5 Conversion to Direct Solar Powered (w/Solar Panels)

Valor has evaluated the conversion from instrument gas actuation to solar direct actuation. A major safety concern is that the electric actuated valves are “failed in last state”, meaning that they are not designed to fail in a safe position (i.e., closed) as is usually required for oil and gas operations. In order to get a fail-safe electric actuated valve, the actuator must be equipped with a battery or a capacitor. Such is the case with the electric offerings from Kimray and Fisher. However, Valor is not aware of any proper failure modes and effects analysis (FMEA) on these components to provide assurance of reliability. As such, the battery or capacitor in these valves could be single point failure that could be a risk for the safety of the facility. Valor strongly discourages use of electric direct actuation valves at facilities requiring fail-safe conditions or requiring Process Safety Management (PSM) process such as 29 CFR 1910.

Furthermore, Valor has reviewed the ERG data related to conversion of facilities to solar powered/electric actuated and determined that the costs for conversion are underestimated. Specifically, “Pneumatics Reductions and Costs VOC 5-27-2021”, tab “Study Data”, cell B110 to D110. The costs for electric actuators for 1” and 2” valves and pneumatics in cell B110 are within reason, however, the solar panel and battery estimation in C110 is underestimated. The reason is the amperage draw for 1” and 2” valves (most typical in the upstream production facilities) is between 2 and 4 amps at 12/24 VDC as shown below.

ADAPTERS				
Order Code	Description	Line Size	ISO 5211	Shaft
YHN	R2L-1	1"	F05	14mm SQ
YHO	R2L-2	2"	F07	14mm SQ

ELECTRIC ACTUATORS AVAILABLE				
Order Code	Description	Voltage	ISO 5211	Torque
KSRADCWX	VALVCON ADC	MULTI	F05/07	600in lb

	230VAC	115VAC	24VAC	24VDC	12VDC
CYCLE TIME (SEC/90°)	14	14	13	13	17
CURRENT DRAW (AMPS)	0.5	0.6	2.5	1.7	2.8

NOTES:
For standard & optional seals, metals, Cf Cv values, material specifications & dimensions see technical data on pages 01:I - 01:XI

Solar systems are designed for three days of no sunlight (3-day autotomy). With that considered and assuming 100 amp-hr batteries, a facility with five (5) electric controllers cycling 2 times per minute would need 1 x 100 a-h battery and two, 300W solar panels and a Sunsaver (which regulates charge to the batteries). Furthermore, liquid level controllers and “HiLo” controllers such as the Fisher 4660 would need to be replaced with electric level switches. In addition, these controls need to be tied to a central site programmable logic controller (PLC) or controller that is suitable for Class 1 Division 2 classified service per NFPA 70. Control panels costs range from $5000-10,000, not including mounting hardware. In summary, moving to electric power or solar power for instrument gas controllers is a significant cost. Valor estimates for retrofit are shown below (based on 5 control valves).

Item	Estimated Cost	Qty	Total
5 electric actuators	$3600	5	$18,000
5 associated level switches or pressure transducers	$1200	5	$6,000
100 amp-hr battery (38 amp-hr ~ $700)	$1800 avg	1	$1,800
300 W solar panels	$300	2	$600
Battery box (24” x 18” z 10” Hoffman)	$321	1	$321
Sunsaver	$150	1	$150
Central site PLC (10 I/O basis)	$8,200	1	$8,200
Poles, wiring, mounting hardware, junction boxes, seal offs, labor	$8,000	1	$8,000
		Total:	**$43,071**

When these costs are entered into “Pneumatics Reductions and Costs VOC 5-27-2021”, tab “Study Data”, cell E110, F110, and G110 the “Pneumatics Reductions and Costs VOC 5-27-2021”, tab “Summary Pivot Tables”, cell I29 changes as shown:

Annualized cost per ton VOC Reduced =

WAS:	$2,745
w/ Updated EF:	$7,213
w/Updated EF and solar system and battery costs:	**$10,079**

6 Conclusion

The NMED has proposed regulations on pneumatic controllers that will result in a very high cost per ton of VOC emission reductions. These costs range from $7,904/ton at sites with grid electric power already on site to a high of $23,829/ton on sites like gas well sites with no practical access to grid electric power.

Based on these costs, Valor EPC recommends that NMOGA propose applicability based on production rates (and by association frequency of pneumatic controller actuation frequency and duration) and for NMED to evaluate the Colorado Rules for pneumatic controllers as an alternative to adopt.

7 References

Applicable NMAC Paragraphs
NMAC 20.2.50.122

Applicable NMED Documents
The following NMED documents were evaluated (reference https://www.env.nm.gov/air-quality/ozone-precursor-rule-hearing/)

1. Pneumatics Reductions and Costs VOC 5-27-2021

References

1. https://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-devices.pdf
2. Valor Memo - Pneumatic Controllers 20.2.50.122 Emissions Factors
3. U.S. EPA. Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. OAR: Natural Gas Star. October 2006. https://www.epa.gov/sites/production/files/2016-06/documents/ll_instrument_air.pdf

Appendices
Appendix A – Vendor Quotes and Datasheets
Appendix B – Calculations

We look forward to discussing this report with you in more detail.

Sincerely,

Adam T. Meyer
Principal, VP US Operations
Valor EPC | ph: 407.697.7289 | email: adam.meyer@valorepc.com

VALOR EPC

Appendix A – Vendor Quotes and Datasheets

SKID PRICING

Unit Price – 15 HP Air Compressor Packages... $ 44,200.00 each

Unit Price – 5 HP Air Compressor Packages... $ 40,240.00 each

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Email Cost Estimate (for 60 HP unit):

Skidded Pkg c/w self framing building
2x100% unit (comp. & dryers)
188 scfm @ 150 psig
Gardner Denver L45-125 Compressors
60 hp 460V/3ph/60Hz
$262,000 CAD / $211,300 USD

Description
[redacted] Services: • Structural skid design and drawings • [redacted] generated P & ID's • [redacted] General Arrangement drawings • [redacted] Electrical One Line: 480 VAC, 3 Phase • Electrical Schematic Drawing: 24VDC low voltage **Structural Skid and Building:** • Fabricated structural steel skid to be 10' long x 7' wide. • Fabricated steel skid to be made from structural steel tubing and include ¼" deck plate, lifting eyes, and grounding blocks. • Steel skid will be cleaned, primed, and then coated with an industrial enamel top coat. • Metal Building to be 10' long x 7' wide x 8.5' wall height. • Metal framed building utilizing Unistrut and structural tube sections. • Building wall panels with an insulation value of R-16. • Building roof panels with an insulation value of R-24 • The skid shall be considered unclassified. • CDOH Compliant/Inspected/Approved with (1) one double door. **Ingersoll Rand Compressor and Dryer Equipment:** • Qty 1 – Ingersoll Rand Model FP15HPNG, 15 HP Fixed Speed Reciprocating Air Compressor. Mounted on a 120 gallon horizontal air receiver. Capacity is at 50 ACFM @ 125 PSI at 5,280' or 35-40 SCFM at standard conditions. • Qty 1 – Ingersoll Rand DA100IM Heatless Regenerative Desiccant Dryer with factory installed dew point controller and pre filter and post filter. Dryer designed to produce a -40 F dewpoint. **Compressed Air Piping, Valves & Instruments:** • All Threaded Steel Piping, Fittings, and Valves as required to provide a complete compressed air system, including connection and valving of all components. **Electrical Equipment:** • 100 Amp Fused disconnect mounted to the exterior of the building wire to 480 VAC panelboard • 100 Amp, 480 VAC, 3 Ph Panelboard with Main Lug and feeder circuit breakers. • 7.5 kVA Mini Power Center, 480 VAC x 120 VAC, with Main Circuit Breaker, and feeder circuit breakers. • 1 – LED Interior Ceiling Mount Light • 1 – Canarm Exhaust Fans w/ intake louvers • 1 – 120 VAC Receptacle • 1 – 120 VAC Baseboard Heater with Thermo-Stat • 1- DC junction box mounted on building exterior for compressor status. • Conduits, Cabling, Terminations required for complete system **[redacted] Testing:** • [redacted] ill provide a shop test of the completed instrument air skid that includes powering it up with 480 VAC, 3 Ph power, and insuring the operation of the system.

Pricing:

Item	Quantity	Description	Unit Price	Extension
1	**1**	**[redacted] Reciprocating IA Skid**	**$ 66,413.00**	**$ 66,413.00**
1A	**1**	**Adder for Rotary Screw**	**$ 1,131.00**	**$ 1,131.00**

Description WO 202102022 APPLICATION FEE FOR TH[redacted]WELL PROJECT LOCTED AT [redacted]

THIS INVOICE IS VALID FOR 90 DAYS. UNITED POWER WILL NOT ACCEPT ANY CHECK WITH LIEN WAIVER LANGUAGE.

CATALOG ITEM	DESCRIPTION	QUANTITY	UOM	UNIT PRICE	AMOUNT	TAX
1418194	NON REFUNDABLE CONST COST (ESTIMATED MATERIAL AND LABOR COST)	1.000	EA	32,353.0000	32,353.00	
PIF	PIF FEE (PLANT INVESTMENT FEE)	1.000	EA	3,375.0000	3,375.00	
PT-3 PHASE UG	PT METER-3 PHASE UG (NON REFUNDABLE) (PT METERING FEE)	1.000	EA	13,300.0000	13,300.00	
1418192	APPLICATION FEE - NONREFUNDABLE (APPLICATION/DESIGN FEE)	-1.000	EA	2,250.0000	-2,250.00	

TOTAL ORDER AMOUNT: $ 46,778.00

2. Commercial Proposal

This quote is valid for 30 days after time of issue.

2.1. 6 kW Lump Sum Pricing

Item	Quantity	Unit Cost	Total
6 kW EPOD AP6 Mini c/w FS Curtis CA5 (Simplex) 80G 5 HP Reciprocating I/A Compressor	1	$ 63,073.41	$ 63,073.41
Commissioning & Field Support (1 day field commissioning, 2-day travel)	1	$ 2,500.00	$ 2,500.00
Total			$ 65,573.41

2.2. Available Optional Add-Ons

Add On	Details	Cost
Increase from Simplex to Duplex 5 HP base mount compressors	Replace Simplex Compressor and install duplex 5 hp base mount air compressors with an 80 gal receiver.	$ 4,762.57
Increase to 20 kW generator and from Simplex 5 HP to Simplex 15 HP compressor	Upgrade 6 kW generator to 20 kW and replace Simplex 5 HP compressor with Simplex 15 HP compressor.	$ 14,059.13
Include 10.4 kWhr UPS	Upgrade to 10.1 kWhr 24VDC Lead Carbon UPS c/w 6 kW Inverter-Charger	$ 13,803.16
Include Solar Panel Skid (UPS required)	Include 4.86 kW Solar Panel Array (12 x 405W bifacial) c/w charge controller and accessories	$ 12,447.17
CDI Air Flow Meter	Supply and install 0-20 SCFM Instrument Air Meter	$ 1,560.42
24 VDC Distribution	Supply and installation of additional 10 amp 24 VDC service.	$ 366.60
Exterior ESD Pushbutton	Supply and install an ESD Button & protective shroud.	$ 576.43
Exterior Light Fixture	Supply and install of an exterior LED light fixture.	$ 442.51
Exterior Stack Light	Supply and install of an exterior stack light for unit status indication (green/amber/red)	$ 447.47
External NEMA 3R Wireway	Supply and install of 6' of NEMA 3R Wireway.	$ 489.09
Fuel Gas Sweetening Package	Includes One Drum of Absorbital & 32 oz. Thief Hatch (Made by Amgas, does not include required Amgas Technician time)	$ 9,302.51
Gas Detection	Supply and install of a Emerson Net Safety SC310 LEL Detector with display and remote sensor.	$ 3,076.02
Backup Generator	9 kW Portable Gasoline Generator c/w Electric Start, 29L fuel tank	$ 1,293.88
Enclosure Wrap	Full color premium laminated vinyl wrap of EPOD Mini enclosure	$ 1,790.74
Spares Set: IA Compressor	5 HP Maint. & Spare Parts Kit: Belts, Oil, Filter, Tune up.	$ 613.36
Spares Set: Generator	6 kW Maintenance and Spare Parts Kit.	$ 2,219.73

Freight:	Delivery Terms:	CPT:	Payment Terms:	Pricing Valid:
Best Way	CPT	Shipping Point	Credit Card	30 Days

All lead times provided are based upon availability at the time of quote

Item	Description	Qty	Unit Price	Net Extended	Lead Time
1	Fisher easy-Drive 200L bare-stem Actuator with RPU-100	1	$3,506.40	$3,506.40	8 Weeks ARO
2	Fisher D3, 1" NPT body, easy-Drive on/off actuator with RPU-100	1	$3,576.00	$3,576.00	8 Weeks ARO

Item Number:	2908237 (Click to view datasheet)
Description:	UPS-BAT-KIT-VRLA 2X12V/38AH
NCNR Status:	This item is **non-cancelable / non-returnable**
Defective RMA Request:	Contact Customer Service
Price (each):	$696.15 Disc Code: C17 + $54.2927 Tariff Fee - Effective Date 01/01/2021

VALOR EPC

Ln #	Item #	Description	U.O.M	List Price	QTY Ship	Net Price	Extended Price
10	8280	P-5050N-24-RS-FA	Each	8,300.00	1.00	8,300.00	8,300.00
20	6465	STAND, 1 TEG, 5120/5060/5220	Each	696.00	1.00	696.00	696.00
30	8080	P-5100N-24-RS-FA	Each	10,100.00	1.00	10,100.00	10,100.00
40	6465	STAND, 1 TEG, 5120/5060/5220	Each	696.00	1.00	696.00	696.00
50	8421	1120N-24-SI-SO, C1D1, w/ RAIN	Each	21,700.00	1.00	21,700.00	21,700.00
60	6666	STAND, 1 TEG, 1120	Each	696.00	1.00	696.00	696.00

MODEL P-5050

Thermoelectric Generator

The Model P-5050 Thermoelectric Generator contains n moving parts. It is a reliable, low-maintenance source of D electrical power for any application where regular utilities a unavailable or unreliable.

KEY DESIGN FEATURES:

- Automatic Spark Ignition (SI)
- Automatic Fuel Shut-Off (SO)
- Fuel Filter
- Low Voltage Alarm Contacts (VSR)
- Reverse Current Protection
- API 12N Flame Arrestor (Natural Gas Only)
- Certified to CSA Std. T.I.L. R-10; CE

OPTIONAL FEATURES:

- Remote Start
- Corrosive Environmental Fuel System
- Cathodic Protection Interface
- Pole Mount or Bench Stand

Power Specifications	Power Rating at 20°C (68°F):
	50 Watts @ 14 Volts 50 Watts @ 27 Volts
Electrical	Output Adjustment Range:
	12 V 12–18 Volts 24 V 24–30 Volts

Output: Terminal block which accepts up to 8 AWG wire. Opening for 3/4" conduit in base of cabinet.

Fuel Requirements	Natural Gas:
	4.8m³/day (168 Sft³/day) 1000 BTU/Sft³ (37.7 MJ/Sm³) gas max 115 mg/Sm³ (~170 ppmw) H_2S max 120 mg/Sm³ H_2O max 1% free O_2
	Propane:
	7.2 l/day (1.9 US gal/day)
Max. Supply Pressure:	344 kPa (50 psi)
Min. Supply Pressure:	103 kPa (15 psi)
Fuel Connection:	1/4" MNPT

MODEL P-5100

Thermoelectric Generator

The Model P-5100 Thermoelectric Generator contains r moving parts. It is a reliable, low-maintenance source of D electrical power for any application where regular utilities a unavailable or unreliable.

KEY DESIGN FEATURES:

- Automatic Spark Ignition (SI)
- Automatic Fuel Shut-Off (SO)
- Fuel Filter
- Low Voltage Alarm Contacts (VSR)
- Reverse Current Protection
- API 12N Flame Arrestor
- Certified to CSA Std. T.I.L. R-10; CE

OPTIONAL FEATURES:

- Remote Start
- Corrosive Environmental Fuel System
- Cathodic Protection Interface
- Pole Mount or Bench Stand

Power Specifications	Power Rating at 20°C (68°F):
	100 Watts @ 14 Volts 100 Watts @ 27 Volts
Electrical	Output Adjustment Range:
	12 V 12–18 Volts 24 V 24–30 Volts

Output: Terminal block which accepts up to 8 AWG wire. Opening for 3/4" conduit in base of cabinet.

Fuel Requirements	Natural Gas:
	9.4m³/day (332 ft³/day) 1000 BTU/ft³ (37.7 MJ/Sm³) gas *1200 1500 BTU/ft³ (45.2–56.5 MJ/Sm³) gas max 115 mg/Sm³ (~170 ppmw) H_2S max 120 mg/Sm³ H_2O max 1% free O_2

*Gas factory options

	Propane:
	13.8 l/day (3.6 US gal/day)
Max. Supply Pressure:	344 kPa (50 psi)
Min. Supply Pressure:	103 kPa (15 psi)
Fuel Connection:	1/4" MNPT

Appendix B – Calculations

5 electric controller battery and solar panel estimate:

PER Valve:

$$2.8\ \frac{\text{A}}{\text{Valve}} \times \frac{2\ \cancel{\text{rotations}}}{1\ \cancel{\text{cycle}}} \times \frac{17\ \cancel{\text{seconds}}}{1\ \cancel{\text{rotation}}} \times \frac{1\ \text{hour}}{3600\ \cancel{\text{seconds}}} \times \frac{4\ \cancel{\text{Cycle}}}{1\ \cancel{\text{Hour}}} \times 72\ \cancel{\text{Hours}} = 7.616\ \frac{\text{A-H}}{\text{Valve}}$$

Energy Required to Fully Charge the Batteries:

$$47.07\ \text{A-H} \times 12\ \text{V} = 564.8\ \text{W-H}$$

Power Required to Full Charge the Batteries in 6 Hours

$$564.8\ \frac{\text{W-}\cancel{\text{H}}}{\cancel{\text{Charge}}} \times \frac{1\ \cancel{\text{Charge}}}{6\ \cancel{\text{Hours}}} = 94.1\ \text{W}$$

Given a Panel Efficiency of 20%

$$94.1\ \text{W} \times \frac{1}{0.2}\ \text{Efficiency} = 470.7\ \text{W}$$

Check #1: Panel Charging Capacity

$$500.0\ \cancel{\text{W}} \times 0.2\ \text{Efficiency} \times \frac{6\ \cancel{\text{Hours}}}{1\ \cancel{\text{Charge}}} \times \frac{1\ \cancel{\text{Charge}}}{564.80\ \cancel{\text{W}}} = 1.1\ \text{Full Charge}$$

Check #2: Equivalent Hour Runtime

$$\frac{2\ \cancel{\text{rotations}}}{1\ \cancel{\text{cycle}}} \times \frac{17\ \cancel{\text{seconds}}}{1\ \cancel{\text{rotation}}} \times \frac{1\ \text{hour}}{3600\ \cancel{\text{seconds}}} \times \frac{4\ \cancel{\text{Cycle}}}{1\ \cancel{\text{Hour}}} \times 72\ \cancel{\text{Hours}} = 2.72\ \text{Hours}$$

Date 7/28/21
New Mexico Oil and Gas Association
Attn: John Smitherman

SUBJECT: Valor EPC Study: NMAC 20.2.50.122, Natural Gas-Driven Intermittent Pneumatic Controller Emission Factor

Dear Mr. Smitherman,

Valor EPC is pleased to provide this study and supporting evidence on the subject of a proper emission factor for natural gas-driven intermittent pneumatic controllers in response to the proposed rules to Title 20 Chapter 2 Part 50 (20.2.50 NMAC) paragraph 20.2.50.122. The below study represents Valor EPC's professional opinion based on years of experience and supporting data, to the maximum extent possible, within the schedule required.

Executive Summary

Valor EPC was asked by NMOGA to review the regulations being proposed by New Mexico Environment Department (NMED) as part of a larger effort to assess the impact of the rules on the industry. One element that Valor scrutinized was the emission factors for pneumatic controllers utilized by ERG/NMED in their studies. Valor EPC has reviewed the "Pneumatics Reductions and Costs VOC 5-27-2021" Excel sheet and concludes that the 13.5 scf/hr emission rate utilized for estimating VOC emissions from natural gas-driven intermittent pneumatic controllers is based on outdated studies. The result is that ERG/NMED studies could be significantly overstating emissions from intermittent pneumatic controllers, and subsequently underestimating the cost per ton of VOC for retrofit or replacement of natural gas-driven intermittent pneumatic controllers. Based on more recent data and to align with developments in Colorado as part of their rulemaking, Valor recommends using 3.5 scf/hr emission rate for intermittent pneumatic controllers.

1 Emission Factor Analysis and Rebuttal

In "Pneumatics Reductions and Costs VOC 5-27-2021", NMED has utilized an emission factor of 13.5 scf/hr for the estimate of emissions emanating from natural gas-driven intermittent pneumatic controllers. This emission factor, which is utilized by the EPA in their greenhouse gas reporting regulation (References 1 and 2), is outdated and has repeatedly been shown to overstate emissions from natural gas-driven intermittent pneumatic controllers.

The origin of the EPA's 13.5 scf/hr emission factor utilized by NMED can be traced back to 26 measurements taken over 25 years ago. In the development of their greenhouse gas emissions reporting rule, the EPA cited the API's 2009 Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry as its source for the 13.5 scf/hr emission factor (Reference 3). The Compendium in turn references a Gas Research Institute (GRI)/EPA publication from 1996 as its source of the 13.5 scf/hr emission factor (Reference 4). The GRI/EPA report in turn references 7 measurements taken by Tenneco Gas Transportation in 1994 and Chevron in 1995 as well as a report published by the Canadian Petroleum Association (CPA) in 1992 that contained results of another 19 measurements (Reference 5). In conclusion, the EPA emission factor is based solely on 26 measurements collected over 25 years ago. This data was considered relevant years ago but has been superceded by more recent comprehensive and detailed studies.

Recent studies involving hundreds of measurements (References 6 through 8) have demonstrated that emissions from natural gas-driven intermittent pneumatic controllers are routinely as low as 0.32 scf/hr. These studies are summarized below:

- 2014 Oklahoma Pneumatic Controller Study: measured 659 intermittent pneumatic controllers, reported 0.4 scf/hr average emission rate;
- 2015 Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: measured 322 intermittent pneumatic controllers, reported 2.2. scf/hr average emission rate, and
- 2016 Uintah Basin Pneumatic Controller Study: measured 77 intermittent pneumatic controllers, reported 0.32 scf/hr average emission rate.

The data from these studies are much more robust that the original EPA data and have been recognized by other states in the development of recent regulations promulgated for natural gas-driven pneumatic controllers. The State of Utah has petitioned the EPA for use of a more realistic emission factor (Reference 9). More recently, the Colorado Air Quality Control Commission abandoned the EPA emission factor and instead utilized an emission factor of 3.5 scf/hr in the development of their February 2021 natural gas-driven pneumatic controller rules. We note that this was done at the suggestion of several environmental/conservation groups (see Appendix A). Valor recommends using 3.5 scf/hr as the basis for emissions estimates.

When cell C124 of the “Study Data” worksheet of the “Pneumatics Reductions and Costs VOC 5-27-2021” workbook is changed from 13.5 scf/hr to a more realistic 3.5 scf/hr emission factor the amount of VOC emissions reduced by pneumatic controller replacement decreases by 19,418 tons per year. The resulting correction makes the cost per ton of VOC increase from $2,745/ton to an unreasonably high $7,213/ton, as shown in excel sheet “Pneumatics Reductions and Costs VOC 5-27-2021”, tab “Summary Pivot Tables”, cell I29.

2 Conclusion

Valor EPC believes that NMED has significantly overestimated the benefit and understated the cost of a natural gas-driven pneumatic controller replacement program. Although it is understood that estimating emissions from pneumatic devices is difficult, Valor EPC believes that using the most robust and recent data is important to evaluating emissions. The NMED should rely on the newer studies referenced in this memo as the basis for the new ozone rule. Valor EPC recommends that NMOGA propose a factor of 3.5 scf/hr in the NMED Ozone rule and look to Colorado efforts (Reference 10) to adopt emission reductions for pneumatic controllers.

3 References

Applicable NMAC Paragraphs
NMAC 20.2.50.122

Applicable NMED Documents
The following NMED documents were evaluated (reference https://www.env.nm.gov/air-quality/ozone-precursor-rule-hearing/)

1. Pneumatics Reductions and Costs VOC 5-27-2021

References

1. Table W-1A to Subpart W of Part 98, 40 CFR Part 98
2. EPA. Greenhouse Gas Emissions Reporting From the Petroleum and Natural Gas Industry, Background Technical Support Document. August 2016
3. API. Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry. American Petroleum Institute. Table 5-15, page 5-68. August 2009
4. Shires, T.M. and M.R. Harrison. Methane Emissions from the Natural Gas Industry, Volume 12: Pneumatic Devices, Final Report, GRI94/0257.29 and EPA-600/R-96-080l, Gas Research Institute and U.S. Environmental Protection Agency, June 1996
5. Picard, D.l., B.D. Ross, and D.W.H. Koon. "A Detailed Inventory of CH4 and VOC Emissions From Upstream Oil and Gas Operations in Alberta." Canadian Petroleum Association, Calgary, Alberta, 1992

6. Oklahoma Independent Petroleum Association. Pneumatic Controller Emissions from a Sample of 172 Production Facilities. November 2014
7. Allen, D. T.; Pacsi, A.; Sullivan, D.; Zavala-Araiza, D.; Harrison, M.; Keen, K.; Fraser, M.; Hill, A. D.; Sawyer, R. F.; Seinfeld, J. H. Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers Environ. Sci. Technol. 49, 633-640, 2015
8. Thomas, E. D., P. Deshmukh, R. Logan, M. Stovern, C. Dresser, and H. L. Brantley. Assessment of Uinta Basin Oil and Natural Gas Well Pad Pneumatic Controller Emissions. *J. Environ. Prot.* 8:394. 2017
9. https://documents.deq.utah.gov/air-quality/planning/technical-analysis/research/oil-and-gas/DAQ-2017-011497.pdf
10. https://coloradosun.com/2021/02/19/oil-gas-controllers-colorado-rule-methane-emissions/

Appendices

Appendix A – David McCabe and Lesley Fleishman Memo Re: Average Emissions from Intermittent-Vent Pneumatic Controllers as Reported by Allen et al. (2015)

We look forward to discussing this report with you in more detail.

Sincerely,

Adam T. Meyer

Principal, VP US Operations
Valor EPC | ph: 407.697.7289 | email: adam.meyer@valorepc.com

APPENDIX A – McCabe and Fleishman Memo

Average Emissions from Intermittent-Vent Pneumatic Controllers as Reported by Allen *et al.* (2015)

David McCabe
Lesley Fleischman
Clean Air Task Force
December 2015

Allen *et al.* (2015) reports the results of a new set of measurements of emissions from 377 pneumatic controllers at 65 oil and natural gas production sites (largely natural gas sites).[1] Allen *et al*. (2015) reports that the average whole gas emission rate from all pneumatic controllers they sampled was 5.5 standard cubic feet per hour (scfh). This emissions factor is lower than the average emissions factor for all pneumatic controllers reported from earlier measurements of 305 pneumatic controllers by Allen *et al*. (2013), 11.2 scfh.[2] Allen *et al*. (2015) attribute the lower emissions per controller (as compared to Allen *et al*. (2013)) primarily to the large number of controllers they observed that did not emit.[3] Allen *et al.* (2015) also reports that the wellsites they surveyed had 2.7 pneumatic controllers per well, a much higher figure than the activity ratio used by the USGHGI of 1.0 pneumatic controller per well. As Allen *et al*. (2015) discuss, it is possible that well site operators are often not counting intermittent- bleed pneumatic controllers that rarely actuate, such as controllers for emergency shut-off devices, in their counts of pneumatic controllers for purposes such as greenhouse gas reporting.[4] Previous research efforts may have similarly undercounted these controllers. When these controllers are included, average emissions per controller decrease.

Notably, Allen *et al*. (2015) reports that the average emissions rate from "intermittent-vent" pneumatic controllers in their sample was 2.2 scfh. This is considerably lower than the emissions factor for "intermittent-bleed pneumatic devices" in EPA's Greenhouse Gas Reporting Program, 13.5 scfh,[5] or reported by Allen *et al*. (2013), 17.4 scfh.

However, the average emissions for intermittent-vent controllers from Allen *et al*. (2015) is *not* directly comparable to the emissions factors from those other sources. Allen *et al*. (2015) labeled controllers empirically, "based on the pattern observed during measurement."[6] In cases where controllers that were designed to bleed intermittently were functioning improperly and continuously bleeding gas, Allen *et al*. (2015) labeled the controller as "continuous bleed" if the continuous bleed constituted the dominant source of emissions. As an example, the time trace of controller LB07-PC02 is shown below in Figure 1. Functionally, this device is clearly an intermittent-bleed pneumatic controller. However, Allen *et al*. (2015) treat this device as a continuous-bleed controller.[7] This controller is not unique in the Allen *et al*. (2015) dataset. A total of seven controllers (including LB07-PC02)[8] are labeled as continuous-bleed by Allen *et al*. (2015), but were observed to actuate (actuations listed in table S4-5).

[1] Allen D.T. *et al.* (2015), "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers," *Environ. Sci. Technol*. **49**, 633−640.
[2] Allen, D.T., *et al.* (2013), "Measurements of methane emissions at natural gas production sites in the United States," *Proc. Natl. Acad. Sci. USA* 110(44):17768-17773.
[3] Allen *et al*. (2015) at 638.
[4] Ibid.
[5] See Table W-1A to Subpart W of 40 C.F.R. Part 98.
[6] Allen *et al*. (2015) at 634.
[7] Allen *et al*. (2015) at table S4-2 (page S-24).
[8] Controller IDs OF07-PC01, LB07-PC02, AA02-PC07, XQ01-PC04, GZ03-PC01, AA02-PC06, and CW02-PC33.

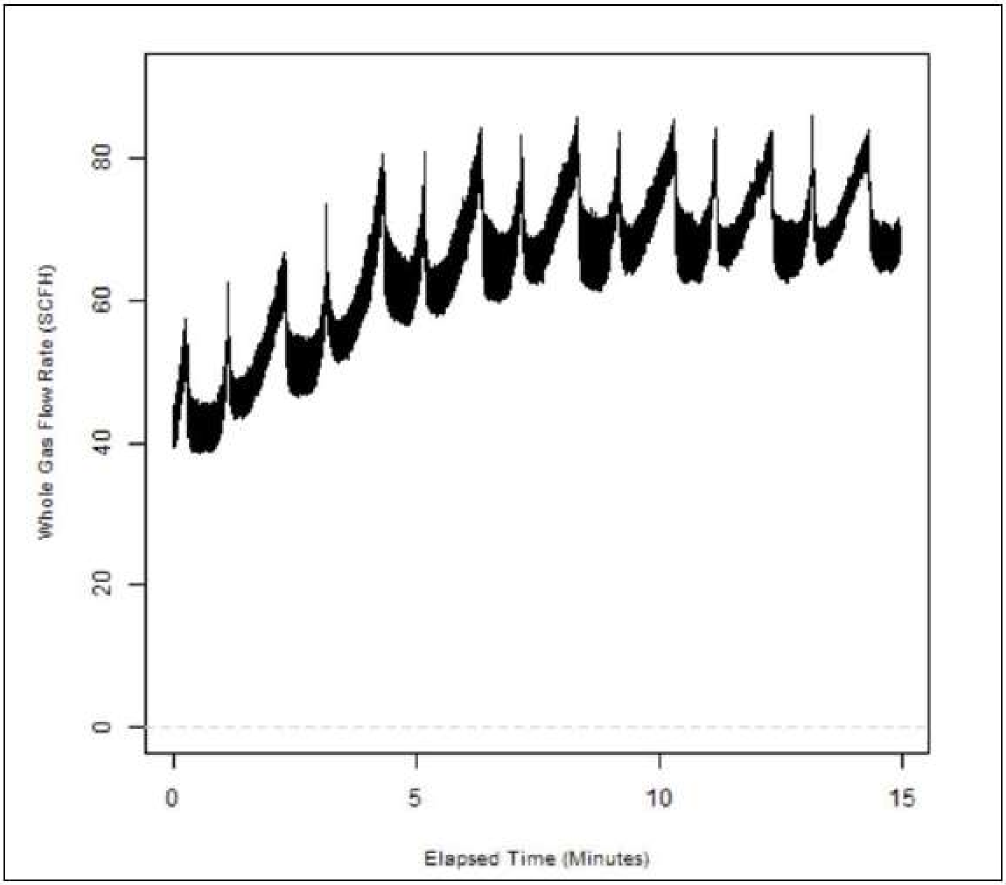

Figure 1. Time trace of controller LB07-PC02 from Allen *et al*. (2015). Source: Allen *et al*. (2015), supporting information, section S8 (page S-86).

Two of these controllers are very high emitters, with emission rates over 35 scfh whole gas. All but one of these seven controllers emit more gas than the 2.2 scfh reported as the average for intermittent-vent controllers by Allen *et al*. (2015). The average emission rate for these 7 controllers was 18.0 scfh.

As discussed by Allen *et al*. (2015) and elsewhere, pneumatic controllers frequently function improperly and as a result bleed more natural gas than they are designed to emit. Intermittent-bleed controllers will typically malfunction by emitting continuously, while it would be very unusual for a continuous-bleed controller to malfunction by emitting intermittently. As a result, the approach taken by Allen *et al*. (2015) *systematically* biases low their results for "intermittent-vent controllers," relative to average emissions for functional intermittent-bleed controllers, by labeling intermittent-bleed controllers that are high-emitting due to continuous leaks as continuous-vent controllers.

Simply combining the seven controllers discussed above with the 320 controllers that Allen *et al*. (2015) have labeled as "intermittent-vent" yields an average emissions factor for the combined set of 327 controllers, 2.55 scfh, that is 15% higher than Allen *et al*. (2015)'s result for "intermittent-vent controllers."

However, it is very likely that additional pneumatic controllers that are functionally intermittent-bleed are classified as continuous-vent controllers. This is because if an intermittent-bleed controller did not actuate during the observations, but (improperly) leaked gas, Allen *et al*. (2015) probably classified it as continuous-vent. Since a large portion (75%) of the controllers that were classified as intermittent-vent did not actuate during the observations, this scenario is very likely. Indeed, there are twelve non- actuating controllers that operators classified as intermittent-bleed and Allen *et al*. (2015) classify as continuous-vent. Emissions from these devices range from 2.9 – 111.4 scfh, with all but one emitting 6 or more scfh. The average from this set of controllers was 29.5 scfh. It is likely that most or all of these devices were actually functional intermittent-bleed controllers that were classified as continuous-vent devices due to improper continuous emissions.

If we assume that all of these devices are in fact intermittent-bleed controllers, as the operators classified them, and combine this set with the set of 327 controllers described above, the average emissions for the combined set (n = 339) is 3.5 scfh, 58% higher than the intermittent-vent emissions factor reported by Allen *et al*. (2015).

There are probably other devices in the dataset that were non-actuating intermittent-bleed controllers that were improperly emitting continuously. 29 controllers that were not classified as either intermittent-bleed or continuous-bleed by operators were classified as continuous-vent in the dataset. These devices also have high emissions (average 17.8 scfh). Given the high proportion of intermittent- bleed devices in the dataset, and the fact they often improperly emit continuously, it is probable that a number of these are also functionally intermittent-bleed controllers. Inclusion of those devices in the dataset would further increase the average emissions for intermittent-bleed controllers in the dataset.

In conclusion, the reported average emissions for "intermittent-vent" pneumatic controllers from Allen *et al*. (2015) is not representative of functional intermittent-bleed pneumatic controllers, that is, pneumatic controllers that are designed to bleed natural gas intermittently.

Date 7/28/21
New Mexico Oil and Gas Association
Attn: John Smitherman

SUBJECT: Valor EPC Study: NMAC 20.2.50.119, Heaters

Dear Mr. Smitherman,

Valor EPC is pleased to provide this document that provides references to support redlines to Title 20 Chapter 2 Part 50 (20.2.50 NMAC) paragraph 20.2.50.119.

Applicable NMAC Paragraphs
NMAC 20.2.50.119

Applicable NMED Documents
None

References

State	Regulation	Heater Size (MMbtu/hr)	NO_x Emission Limit (ppmv)	NO_x Emission Limit (lbs/MMbtu)	CO Emission Limit (ppmv)	CO Emission Limit (lbs/MMbtu)	Notable Requirements	Other Notes
New Jersey	NJAC 7:27-19.7 Industrial/commercial/institutional boilers and other indirect heat exchangers	≥ 100 ≥ 50 Major Source	82.6	0.10	None	None	-CEMS for units ≥ 250 MMbtu/hr -Annual Tune-ups	-ELs based on fuel source (numbers in this table are for natural gas) -Gave 3-4 years for implementation.
		≥ 25	41.3	0.05	None	None		
		≥ 5	None	None	None	None		
California	SCAQMD Rule 1146 Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	≥ 75	5	0.006	400	0.296	-Periodic (e.g. 3 or 5 yr) stack testing -Existing sources (prior to SEP 2008 with heat input ≤ 9 billion Btu/yr) can conduct semi-annual tune-ups in lieu of emission limits	-ELs based on source categories
		≥ 20 ≤ 75	7	0.008				
		≥ 5 ≤ 20	9	0.011				

State	Regulation	Heater Size (MMbtu/hr)	NO_x Emission Limit (ppmv)	NO_x Emission Limit (lbs/MMbtu)	CO Emission Limit (ppmv)	CO Emission Limit (lbs/MMbtu)	Notable Requirements	Other Notes
Texas	30 TAC 117 Control of Air Pollution from Nitrogen Compounds Subchapter B (Major Source NAA HGB Area)	≥ 40	20.65	0.025	400	0.296	-CEMS (NOx) for units ≥ 200 MMbtu/hr	-ELs vary based on inlet air temp -Existing sources (prior to June 1993) ≥ 100 MMBtu/hr subject to 0.10 lbs/MMbtu EL
		> 2 < 40	30	0.036				
	30 TAC 117 Control of Air Pollution from Nitrogen Compounds Subchapter D (Minor Source NAA HGB Area)	> 2	30	0.036	400	0.296		

Appendix A3 – Direct Testimony of Justin Lisowski

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION
20.2.50 **No. EIB 21-27 (R)**
Oil and Gas Sector – Ozone Precursor Pollutants

TESTIMONY OF JUSTIN LISOWSKI

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. Justin Lisowski, 3755 Dudley Street, Wheatridge, CO 80022

Q. WHAT IS YOUR INVOLVEMENT IN THIS PROCEEDING?

A. I am working for Valor EPC to provide technical expertise for NMOGA on New Mexico ozone rulemaking. My focus areas are Engines & Turbines and Compressor Seals.

Q. WHAT IS YOUR OCCUPATION?

A. Senior Project Engineer and Facility Specialist for Valor EPC and Principal/Owner of OtFox Services Co. LLC.

Q. HOW LONG HAVE YOU HELD YOUR CURRENT POSITION?

A. 3 months with Valor, 4 years with OtFox Services Co. LLC.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from Colorado State University (CSU) with a Bachelor of Science in Mechanical Engineering in 2005. Following my undergraduate studies, I continued as a Graduate Research Assistant at the CSU Engines and Energy Conversion Laboratory, now the CSU Energy Institute Powerhouse Laboratory. I received funding from the Pipeline Research Council (PRCI) for my research of emission retrofit technology for lean burn engines. My final thesis was "Diagnostic Techniques for Precombustion Chambers in Large Bore Lean Burn Natural Gas Engines. I graduated from CSU with a Masters of Science in Mechanical Engineering in 2007.

Q. PLEASE BRIEFLY SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. Following my undergraduate studies, I briefly worked for Sturman Industries, a diesel engine injector R&D facility before returning to CSU to pursue my master's degree. Upon graduation from CSU in 2007 I took a position at Encana Oil & Gas (USA) Inc. and worked there until 2020. I worked a mulitple cross discipline positions with the company, with most of my roles having responsibilities some facet of either rotating equipment or facilities engineering. These positions consisted of a range of technical, advisory, and managerial responsibilities.

Q. WHAT ARE YOUR PROFESSIONAL AFFILIATIONS, IF ANY?

A. I am no longer a member of any professional organizations.

Q. WHAT HAVE YOU BEEN ASKED TO ADDRESS IN YOUR TESTIMONY BEFORE THE BOARD?

A. I was asked by Valor EPC to review and prepare a technical review on behalf of NMOGA on the subject of the New Mexico ozone rules in the areas which I have expertise in, Engines and Turbines, and Compressor Seals.

Q. HAVE YOU PREPARED TECHNICAL REPORTS ON THESE ISSUES?

A. Yes. I have prepared three technical reports/memos for NMOGA

Q. PLEASE LIST THE TECHNICAL REPORTS THAT YOU HAVE PREPARED.

A. Valor Memo - Compressor Seals 20.2.50.114
Valor Memo - Engines and Turbines 20.2.50.113
Valor Memo - NMED Engine Inventory Analysis

Q. DO YOU ADOPT THESE TECHNICAL REPORTS AS YOUR DIRECT TESTIMONY BEFORE THE NEW MEXICO ENVIRONMENTAL IMPROVEMENT BOARD?

A. Yes

Q. ARE THESE TECHNICAL REPORTS ATTACHED?

A. Yes.

By: /s/ Justin Lisowski
Justin Lisowski

Date 28 July 2021
New Mexico Oil and Gas Association
Attn: John Smitherman

SUBJECT: Valor EPC Study: NMAC 20.2.50.113, Engines and Turbines

Dear Mr. Smitherman,

Valor EPC is pleased to provide this study and supporting evidence on the subject of Engines and Turbines in response to the proposed rules to Title 20 Chapter 2 Part 50 (20.2.50 NMAC) paragraph 113. The below study represents Valor EPC's professional opinion based on years of experience and supporting data, to the maximum extent possible, within the required schedule.

Executive Summary

New Mexico Oil and Gas Association (NMOGA) has asked Valor EPC to analyze the New Mexico Environment Department (NMED) Proposed Rule 20.3.50.112 "Engines and Turbines" and associated documents and draft a technical commentary. The commentary is to identify new requirements that are technically infeasible and/or impractical from an economic standpoint. Valor EPC suggests that NMOGA propose revisions to the proposed applicability and emissions standards for this part as follows:

1. The data inventory provided by NMED has significant errors that an accurate cost and emissions impact analysis cannot be performed for New Mexico operators.
2. The emission regulations for existing engines are technical infeasible for many legacy and lean burn engines.
3. CO should be removed as it is not an ozone precursor and is already regulated via NSPS JJJJ.
4. Proposed regulations are more stringent for reciprocating engine lean burn engines over rich burns, essentially favoring one manufacturer over another. For existing engines, the focus should be on what is practically achievable in a cost-effective manner for each engine class, likely requiring tiering to reflect the current market structure. For new engines, emission limits can be more technologically agnostic and still may need to be structured in a tiered fashion.
5. Turbine emission limits are technically infeasible for smaller horsepower ranges and should be revised.
6. For engines and turbines, maintenance rules should be structured intentionally, with focus to specifically impact emission levels to reduce ozone generation without generating undue administrative and cost burden to operators.

Valor EPC recommends revisions to the engine emission limits for both new and existing units to reflect practically achievable NOx limits. It is recommended to remove CO or at a minimum mirror NSPS JJJJ. It would be beneficial for NMED to scrub the engine database of erroneous data to more accurately represent the inventory of affected units, improve the economic impact assessment to operators, and establish more representative emission tonnage reduction expectations. While preparing the final rule, efforts should be made to ensure that the regulations align with overall objective to reduce ground level ozone generation and not create undue administrative burden for operators.

1 New Mexico Environment Department Report and Data Review

New Mexico Environment Department (NMED)– Air Quality Bureau Equipment Reports #1-4)
Valor has reviewed the referenced equipment reports and determined that there are errors in NMED data used for NOx emission reduction. See Valor Memo - NMED Engine Inventory Analysis for more detail.

Furthermore, selective catalytic reduction (SCR) and NOx Adsorber (not "Absorber" as referenced by NMED) cost estimates are referencing documents[1,2] from 2005 when SCR was in its infancy without any significant commercial applications or product offerings. Although NOx adsorber technology is very effective at reducing NOx, it has never been a viable emission reduction technology on industrial engines because it needs a frequent cycling of oxidative and reducing exhaust environments to function properly. The only engines that cycle in this manner are rich burn engines (where this technology would not be applicable.) Additionally, the catalyst suffers degradation issues due to sulfur poisoning and high temperature degeneration[3] which limits its usefulness in sour gas applications.

The NMED NOx and VOC studies also made significant assumptions when applying "low emission combustion" (LEC) technology and selective catalyst reduction (SCR) in that the capital costs can be converted into a capital recovery factor, rather than direct capital expenses. This creates an illusion that costs to meet proposed rules are trivial and misrepresents that true cost of meeting these new emission limits. Rather than the true cost for operators in New Mexico in the millions, a more realistic number for retrofits and new builds will be possibly in the billions of dollars. It is important to consider that there can often be a disproportionate cost impact of LEC technology and SCR implementation for lower HP engines versus larger units or units that are already operating at relatively low NOx and VOC levels, but not meeting proposed limits. These units are typically subject to the same or similar retrofit costs as the larger units causing significant costs to be expended for minimal reduction benefits. In some cases, including a cost per HP and include tonnage reduced offers additional insight into the economic impact of retrofit costs.

Ultimately, the data inventory provided by NMED has significant errors that an accurate cost and emissions impact analysis cannot be performed for New Mexico operators.

2 Comments on Proposed NMED Rules (in order as presented in rule)

20.2.50.113 A

- Need definition of "portable" (and/or need to remove portable from rule) to clarify impact of rule. Portable makes up extremely small percentage of units plus they are almost entirely <500HP, making the proposed rules not applicable. Using the NMED spreadsheet[4] and omitting known erroneous data points, approximately 83% of engines are under 1000 HP (78% ≤500 HP). Retaining "portable engines" in the rule for the small subset of >1000 HP (17% of portables)

[1] Parise, T (2005). Cost per Ton for NSPS for stationary compression ignition (CI) internal combustion engine (CE.) Alpha-Gamma Technologies, Inc., to Sims Roy, EPA OAQPS ESD Combustion Group. EPA Docket Item No. EPA-HQ-OAR-2005-0029-0014

[2] Riddle, B. (2006). Control Technologies for Internal Combustion Engines. Alpha-Gamma Technologies, Inc., to Jaime Pagan, EPA Energy Strategies Group. EPA-OAR-2005-0030-0054.

[3] James E. Parks II, H. D. (2012). NOx reduction with natural gas for lean large-bore engine. Knoxville, TN: Oak Ridge National Laboratory.

[4] ICE Reductions and Costs VOC 6-4-21_erg (06-08-2021R).xlsx and ICE Reductions and Costs NO2 6-4-21_erg (06-08-2021).xlsx

creates a potential economic burden and technical infeasibility on operators that operate these engines if emission levels cannot be met with LEC (installed on lean burn engines) or non-selective catalytic reduction (NSCR, rich burn engines) requiring the use of SCR. SCR systems for natural gas stationary engines are sourced via aftermarket suppliers, not engine manufacturers. They have logistical challenges with the need for physical space (at the facility) for all the equipment and electrical power to operate. Sites without power are further challenged. SCR in portable use is technically impractical due to space constraints (refer to Figure 1 in appendix) and technically infeasible for the electrical power requirements to operate SCR that may or may not be available on a given site.

20.2.50.113 B

- Part (d): In situations of non-compliance, the proposed allowance for reducing annual operating hours such that annual tonnage for NOx and VOC emissions are reduced by $\geq$95% is unreasonable. Non-compliant engines should be allowed to operate either with a state waiver (i.e., essential operation), an approved alternative compliance plan or an enforceable annual tonnage for regulated pollutants (NOx and VOCs) that does not exceed the equivalent allowable ton per year emission as set forth in Table 1 or Table 2.
- Part (e): Valor recommends that there should be opportunities within the rule to allow for alternative compliance plans, waivers or exclusions for uneconomic retrofit capital cost requirements (e.g. costs to apply existing technologies that exceed replacement costs),"NOx credits" or equivalent to allow for non-compliant engines (either in critical service or economically challenged applications) to exceed the proposed rules while in another area of operation engines achieve more stringent emission levels, demonstrating a fleetwide average meeting the proposed emission limits. Any of these approaches can obtain the emissions reductions sought by NMED while reducing the cost and burden on New Mexico operators.
- Sections 20.2.50.2 and 20.2.50.7 clearly state that the scope and objective of the Part is to establish emissions standards for ozone precursors, volatile organic compounds (VOC) and nitrogen oxides (NOx), in specific counties. As such, including emission standards, monitoring, recordkeeping, reporting, and testing requirements for CO should not be included in the rulemaking. Valor recommends that requirements for CO be removed from the proposed rules and allow CO to be regulated by NSPS JJJJ.
- Table 1 (Existing Engines) places an impractical NOx limit of 0.5 g/HP-hr on existing engines. This places undue burden on operators that have legacy engines in operation. Cost examples from various operators (anonymous) are estimated as follows:
  - The cost of applying all applicable LEC technology on a 2-stroke lean burn (2SLB) legacy engine (e.g., high pressure direct injection – HPDI, turbo upgrades, prechambers, etc.) will cost $3 million and still not be able to achieve 0.5g/hp-hr NOx on a 1000-2000 HP unit.
  - Legacy 2SLB engine upgrades in the 1400 HP range is estimated at $4 million
  - Some retrofitted legacy engines can currently meet 0.8 g/hp-hr NOx. However, the estimated cost to bring engines from 0.8 to 0.5 g/hp-hr is close to $2 million/unit.
  - Retrofit LEC packages for the 4SLB Cat 3500 series units is $132,000/engine.
  - Engines required to install SCR are estimated to incur capital costs of $150,000-$200,000 not including maintenance costs, power utility costs to run SCR, space requirements, urea, or anhydrous ammonia consumption costs.

  Most state regulatory agencies recognize the challenges for engines pre-2007 NSPS to meet sub-1.0 g/hp-hr NOx and provide tiered emission regulations for different engine vintages and/or types and are overall more practical and attainable for existing engines.
- Table 1 ("existing engines") applies more stringent CO restrictions towards lean burn engines over rich burn engines. Since CO is not a precursor to ozone creation, Valor recommends that CO

should be removed from the Table or mirror NSPS JJJJ at 2.0 g/HP-hr. Alternatively, lean burn engines should have the same CO limits that are afforded to rich burn engines, rather than the 47 ppmvd @ 15% O2, which is equivalent to 0.40 g/HP-hr. There is no rationale provided to have more stringent lean burn emission limits.

- Table 1: The engines that are most impacted by the existing engine emission limits appears to be legacy engines (generically identified as pre-1980) and Caterpillar G3500s (which is the primary driver for many rental compression units in the 1000-1800 HP range). High capital costs are required to retrofit these engines and most frequently will result in the required replacement of these engines. The only lean burn engines that can achieve 0.3 g/HP-hr NOx are prechambered engines (more on prechambers in later sections). Smaller bore non-prechambered Caterpillar G3500s and Waukesha GL engines, even with the most advanced applicable technology, cannot. Rich burn engines, by nature of their combustion process, coupled with non-selective catalytic reduction (NSCR), can be significantly easier to upgrade than lean burn engines. In HP ranges from 1000 HP – 1800 HP, Waukesha will become the defacto manufacturer. To be clear however, all emission reduction technology upgrades for rich burn engines are aftertreatment control devices. A rich burn engine continuously alternates between oxidative and reducing exhaust environments (i.e., excess oxygen and oxygen deficient environments, respectively) allowing the physics of the NSCR to function properly. Lean burn engines operate with excess air and that creates only an oxidative exhaust environment such that in-cylinder combustion control (i.e., LEC) is the only method to reduce NOx (other than the technically and economically impractical SCR systems).

- PROPOSED TABLE 1 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED OR RECONSTRUCTED BEFORE THE EFFECTIVE DATE OF 20.2.50 NMAC.

Maximum Engine BHP	Emission Standards (g/HP-hr)		
	NOx†	CO*	VOC
All engines >1000 bhp (4-stroke)	2.0 *This is a preferred limit and more technically achievable for older engines that cannot meet the limits without significant LEC retrofit costs, often exceeding the cost of engine replacement. In many instances, applying all the available LEC technology won't achieve 1.0*	2.0 ** CO is not a precursor to ozone creation and should be removed or mirror NSPS JJJJ at 2.0 g/bhp-hr.*	0.7
2-Stroke Lean Burns† >1000 bhp	3.0		

Reference Colo 5-CCR-1001-9 Part E, Table 1, as applicable to 20.2.50 NMAC (JJJJ) and †2-Stroke Lean Burn > 1000 bhp, Reference Colo 5-CCR-1001-9 Part E, Table 2.

20.2.50.113 B (3)

- Upon startup, engines need to be adjusted and tuned to the fuel supply composition, calibrated, verify catalyst gaskets are installed and functioning properly and de-green the catalysts[5]. This is typically performed and verified with the use of a portable analyzer. It is unreasonable and impractical for engines to comply immediately upon startup. NMED should consider adding a grace period for these consistent with the federal standards for new or modified units[6]. Some catalyst manufacturers may de-green catalysts prior to sales whereas some may need to be performed on site. It isn't explicitly known the duration of time need for this process, but it is largely temperature dependent. However, there are various factors that affect exhaust temperature and therefore the de-greening duration. These factors include, but are not limited to, exhaust temperature, catalyst placement, and fuel gas BTU.

20.2.50.113 B (3)

- Table 2: It is inappropriate to structure rules that create a bias against a specific manufacturer. In this case, lean burns engines greater than 1000 HP (primarily Caterpillar manufactured) are being overly scrutinized with the proposed NOx limit set to 0.30 g/HP-hr (uncontrolled) or 0.05 g/HP-hr (with control). Waukesha engines have the majority market share for rich burn engines in the industry, while this engine category (i.e., rich burn engines) is being given more lenient emission standards. It is also perplexing as to why a technically infeasible emission (infeasible for horsepower ratings less than 1875 HP, shown in Figure 1) of level of 0.30 g/HP-hr is singly given to lean burn engines without consideration of impact and followed with an even more difficult and high-cost level or 0.05 g/HP-hr (technically infeasible without SCR). It appears to be written to favor rich burn engines and benefit Waukesha product offerings and/or to specifically favor SCR manufacturers. The NOx limits proposed for lean burn engines forces extremely complicated SCR (with 0.05g/hp-hr NOx levels) that comes with technical challenges to achieve reliable operation, bears an unreasonably high cost, especially when rich burn engines are given more lenient compliance targets.
- Table 2: 0.3 g/HP-hr NOx is a technically infeasible limit for non-prechambered engines. A precombustion chamber (PCC) is utilized on large bore engines, lean burn engines. A PCC is a small volumed chamber (typically 1-2% of the engines clearance volume) that operates at a stoichiometric or slightly rich fuel-to-air ratio and contains the engines ignition spark plug. By igniting the mixture in the PCC, it creates a torch-like flame to ignite an ultra-lean fuel mixture in the main chamber that is below the flammability ignition limit. "Large bore" engines are not explicitly defined, but application of a PCC is limited by (1) physical engine space constraints and (2) PCCs generate significant percentage of engine NOx such that the engine bore must be large enough to dilute the overall engine emissions. The only applicable PCC engines (i.e., engine manufacturers Caterpillar and Waukesha) are Caterpillar G3600 and Waukesha 275 series engines, >1875 HP and >3750 HP, respectively. The Caterpillar G3500 and Waukesha VHP7042GL lean burns are not PCC engines.
- Figure 1 below illustrates the product offerings from Caterpillar and Waukesha, which make up approximately 95% of the engines currently in use in NM subject counties, greater than 1000 HP. There are no lean burn engines capable of meeting 0.3g/HP-hr NOx under 1875 HP. Overlaying the engine count distribution (Figure 2) indicates that the largest HP application range is where

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[5] Knafl, A, S. Busch, M. Han, et al. (2006). Characterizing Light-Off Behavior and Species-Resolved Conversion Efficiencies During In-Situ Diesel Oxidation Catalyst Degreening. University of Michigan, SAE Journals of Fuels and Lubricants.

[6] 40 CFR §§ 60.8

only rich burn engines can achieve the emission levels, creating a single defacto manufacturer, where otherwise two options would be available to operator.

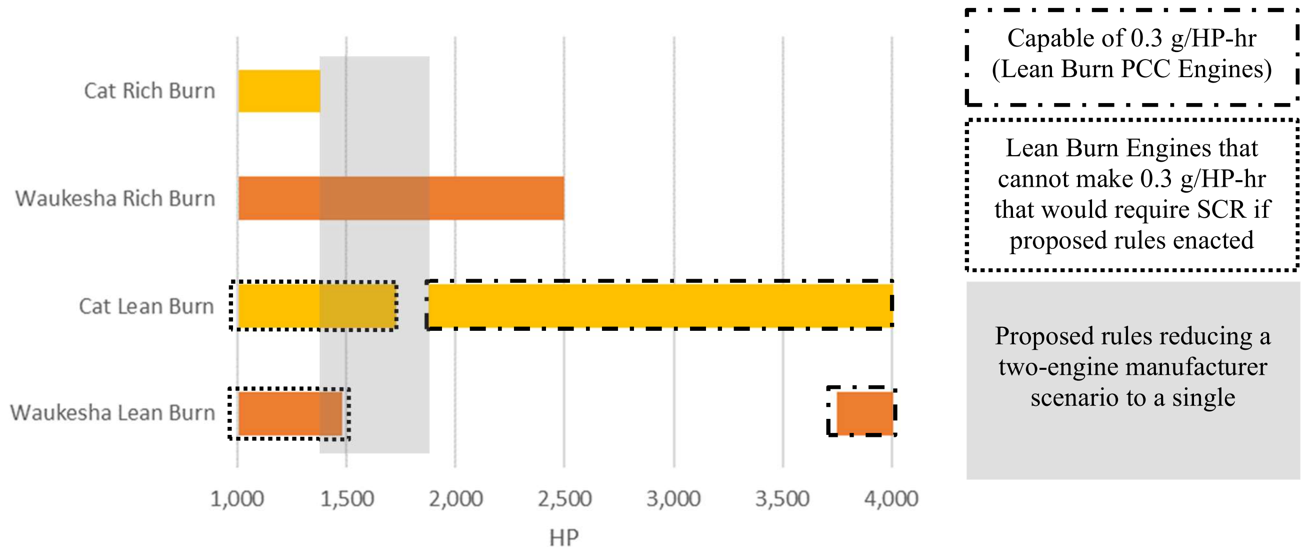

Figure 1: HP ranges for Caterpillar and Waukesha engines >1000 in NM subject counties (the two primary engine manufacturers for oil & gas stationary engines in high HP range). Source, NMED ICE Reductions and Costs NO2 6-4-21_erg (06-08-2021).xlsx, errors omitted.

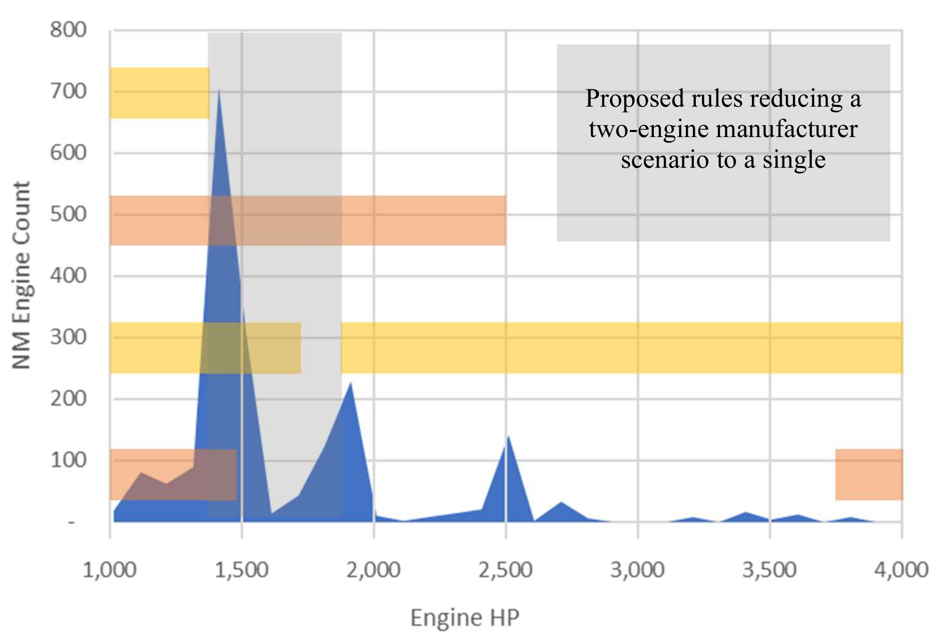

Figure 2: Engine manufacturer HP ranges with engine inventory count in subject NM counties overlay illustrating impact and bias of stringent Lean Burn NOx limits. Source, NMED ICE Reductions and Costs NO2 6-4-21_erg (06-08-2021).xlsx, errors omitted.

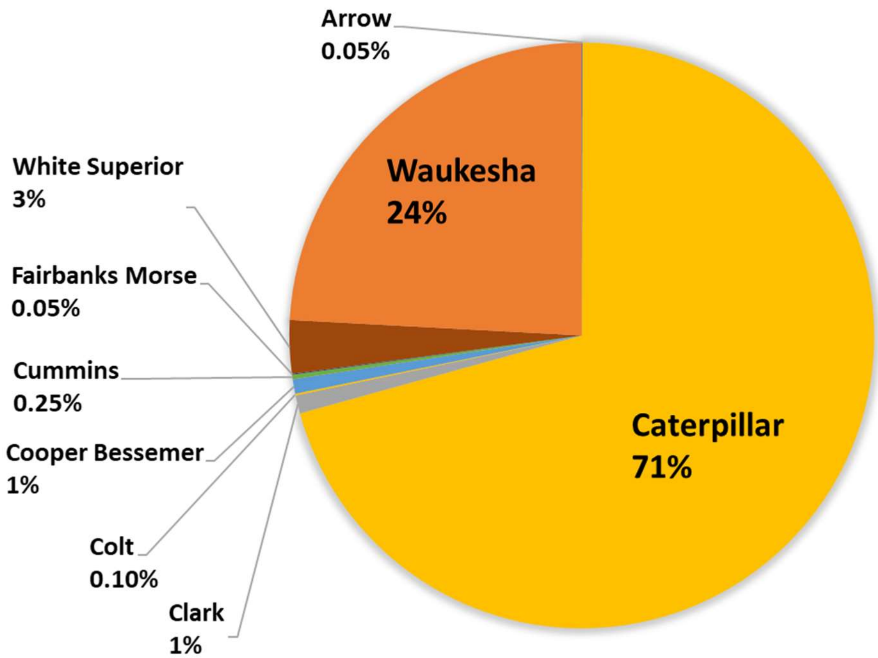

Figure 3: Engine manufacturer distribution (>1000 HP range) in NM subject counties. Source, NMED ICE Reductions and Costs NO2 6-4-21_erg (06-08-2021).xlsx, errors omitted.

- Table 2: Similar to table 1, table 2 applies more stringent CO restrictions towards lean burn engines over rich burn engines. CO is not a precursor to ozone creation and should be removed or mirror NSPS JJJJ at 2.0 g/bhp-hr. Additionally, lean burn engines should have the same CO limits that are afforded to rich burn engines, rather than the 47 ppmvd @ 15% O2, which is equivalent to 0.40 g/HP-hr. There is no rationale provided to have more stringent lean burn emission limits.
- Tables 1 & 2: For existing technologies, the rules should achieve the reasonable maximum reduction for each technology that can be feasibility and cost effectively implemented and certainly should not be favoring one technology over the other. A 0.30 g/bhp-hr lean burn rule will effectively eliminate an entire product offering from Caterpillar, 3500 series engines (~1000-1800hp). Right now, there are effectively two engine manufacturer choices in this space, Waukesha and Caterpillar.
- All emission limits >1000HP: Both existing and new levels should ensure that current manufacturers can maintain product offerings at similar cost without the rules favoring one over the other. "Similar costs" means that regulatory bodies do not impose rules that require excessive additional capital costs to meet regulated levels. An example in this case is the more stringent rules applied just to lean burn engines which will require the use of SCR in lower HP ranges for a specific engine class.
- Rules should be written either (1) a technology agnostic manner such that all engines meet the same regulated limits or (2) pragmatically written so that engine types (i.e., rich burns and lean burns) can meet emission limits without disproportionate scrutiny applied to one over the other. Table 2 does neither.

- PROPOSED TABLE 2 [OPTION 1] - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED OR RECONSTRUCTED AFTER THE EFFECTIVE DATE OF 20.2.50 NMAC.

Engine Type	Engine (HP)	Emissions (g/HP-hr)		
		NOx	CO*	VOC
All Engines	>1000 HP	>0.7† *†0.5 g/HP-hr can be very difficult but technically achievable, however, an emission limit of 0.7 g/HP-hr is more technically feasible and operationally practical allowing for variable and high BTU fuel gas and allow for longer usable life of catalyst elements.*	2.0 ** CO is not a precursor to ozone creation and should be removed or mirror NSPS JJJJ at 2.0 g/bhp-hr.*	0.7

- PROPOSED TABLE 2 [OPTION 1]: The proposed table reflects technology agnostic emission levels for >1000 HP. This proposed table is intended to remove manufacturer bias and create more technology agnostic regulations. However, a more pragmatic approach can be taken (as reflected in the NMED submitted NMOGA NMED 20.2.50 redline document) focusing on a tiered HP and NOx limit based upon what is technically achievable with current product offerings.

- PROPOSED TABLE 2 [OPTION 2] – TIERING TO REFLECT THE CURRENT MARKET STRUCTURE EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED OR RECONSTRUCTED AFTER THE EFFECTIVE DATE OF 20.2.50 NMAC.

Engine Type	Engine (HP)	Emissions (g/HP-hr)		
		NOx	CO*	VOC
Lean Burn†	>1000 - <1875	0.7	2.0	0.7
	≥1875	0.3		
Rich Burn	>1000	0.5		

†If "relocation" triggers the application of "new engine" limits, then the HP tiering needs to be adjusted to 2370 HP

*CO is not a precursor to ozone creation and should be removed or mirror NSPS JJJJ at 2.0 g/bhp-hr.

20.2.50.113 B (4)

- Operators that are forced to implement SCR technology on their lean burn engines (i.e., they cannot meet the disproportionate 0.30g NOx/HP-hr) will be pressed to install electric motor driven compressors over traditional spark ignited (SI). This implementation will decrease Scope 1 emissions and increases Scope 2 emissions (Scope 1 – direct from sources owned or controlled by a company, Scope 2 – indirect from energy that is purchased). Further analysis is necessary to quantify the overall net impact of decreasing Scope 1 emissions and increasing Scope 2 economics. However, to qualitatively bolstering the argument, a 2012 study by the U.S. Energy Department indicates that nearly 72% of NM electrical power generation is sourced from coal powered plants (shown in Figure 4 in the Appendix). Figure 5 from the U.S. Energy Information Administration (EIA) indicates that approximately 54% of NOx comes from coal power generation. This document does not intend to indicate shifting to electric motors will increase NOx emissions overall via Scope 2 emissions. However, it is critical to investigate whether an increase in NOx levels will be an unintended consequence of this proposed rule as operators are not able to meet the emission limits. Furthermore, SCR is extremely complicated and expensive, disproportionately expensive on lower HP engines. Operators estimate SCR cost ranges of $20,000 to $100,000/ton+ NOx. The large range in cost estimates are artifacts of the size and types of engines and turbines that respective operators are utilizing as well as the economic uncertainty of SCR implementation. Figure 4 from a catalyst supply company, also shows how complicated SCR systems are. It highlights that although NMED is trivializing the technology, it is anything but trivial on industrial engines. The agency estimates on average approximately $10,000/ton NOx.

- ERG estimates the rules will reduce NOx emissions by 47,012 tons/year (*Emission Inventory Reductions (06-08-2021).xlsx*). Using NMED figures and industry engine supplier and industry cost estimates, Valor estimates the cost to achieve these reductions are:
    - NMED [$10,000/ton] x [47,000 ton/year] = $470,000,000/year
    - Operator Estimate [$20,000/ton] x [47,000 ton/year] = $940,242,000/year
    - Operator Estimate [$100,000/ton+*] x [47,000 ton/year] = $4,700,000,000/year *This is not representative to apply to the entire NOx tonnage reduction but illustrates that there is significant cost variability depending on the underlying engine or turbine challenging NMED's application of a single cost metric.
    - The initial estimates range from $500 million to nearly $5 billion in capital with no return on investment, highlighting a significant disconnect between NMED figures and NM operators. This is a significant and unreasonable burden placed upon operators. NMED's estimates should work with industry to establish a ceiling for "economically feasible" and costs above those estimates should be considered "economically unfeasible".

20.2.50.113 B (7)

- It is necessary that a similarly staggered schedule be set for existing turbines as for existing engines. The modifications necessary to achieve the thresholds are equally as significant, custom, costly, and time intensive. Compared to engines, the same number of emission source units, if not more, are impacted. At least some suppliers have indicated that they cannot supply turbine retrofits until 2028.
- Table 3: SCR is the only available option to achieve these thresholds on these smaller units <5000 HP. Member companies within NMOGA estimate cost of putting SCR on a unit between 1,000 and 4,000 HP is economically infeasible. New Mexico has many existing turbines in the smallest category that will be unable to meet the proposed standard without SCR control. A higher emissions level, consistent with Subpart KKKK, will allow for dry low NOx (DLN) on compatible

units and allow the smaller turbines, for which DLN retrofits are not available, to continue to operate.
- CO should be removed from the rule consistent with the stated intention of the proposed rules.
- New Turbines Table: Per the NOx standards proposed in the other size categories, it is assumed that the intent of the proposed NMED rule is for compliance to be achieved with DLN combustion retrofits. The 25ppm NOx level is not an appropriate standard for the 1000 to 5000 HP turbine category and per the points above, should be regulated by KKKK.

20.2.50.113 B (9)
- EMT is not addressed in this memo and is being handled within the General provision teams.

20.2.50.113 B (10)
- Emergency use engines should not be subject to this part if it is operated greater than 100 hours per year. By definition, emergency engines are allowed to operate more than 100 hours in the case of an emergency, as defined by 40 C.F.R. §§ 60.4243. The 100 hours is the limit on maintenance/testing (i.e., non-emergency use). Based on size/use of these units, emergency engines should be exempt from this Part 50.

20.2.50.113 C (1)
- Maintenance requirements already exist within ZZZZ and this section should be consistent with that rule. Stationary engine catalysts, housings, and exhaust piping can be provided by the either the engine manufacturer or a catalyst supplier such that following engine manufacturer maintenance guidelines may not have an overall impact on emissions. Good maintenance is required to pass annual emission testing. Many operators establish their own maintenance programs that are more robust.
- (a) and (b) require that routine maintenance and unscheduled repairs >2 hours duration in a 24 hr period must be documented. This creates an administrative burden and has no evidence to support any negative or positive impact on ozone.

20.2.50.113 D (1) (iii, iv)
- (iii) These provisions have no impact on ozone. Maintenance is frequently performed by a third-party service provider, such that there is often poor or incomplete documentation of information unrelated to critical performance of the engine such as that required by the proposed rule. Names of personnel and condition of equipment fall into that category.
- (iv) Provision to record "physical condition of equipment" is vague and ill-defined that will not generate any benefit to reduce emissions or contribute to the maintenance of the referenced equipment.

3 Summary

It is evident via the review of the proposed NMED rules for Engines and Turbines, that it is critical for the agency to revisit proposed rules to ensure that the specific provisions (1) maintenance practices are such that they satisfy the overall objective of reducing ground level ozone formation, (2) are practically applied to existing technology, (3) are technically and economically achievable with existing technology, (4) do not generate unintended consequences, such as disproportionately increasing Scope 2 emission levels.

4 References

Applicable Rule Sections
20.2.50.113

Applicable NMED Documents
The following NMED documents were evaluated (reference https://www.env.nm.gov/air-quality/ozone-precursor-rule-hearing/)

- ICE Reductions and Costs VOC 6-4-21_erg (06-08-2021R).xlsx
- ICE Reductions and Costs NO2 6-4-21_erg (06-08-2021).xlsx
- Turbines Reductions and Costs VOC 6-4-21_erg (06-08-2021).xlsx
- Turbines Reductions and Costs NO2 6-4-21_erg (06-08-2021).xlsx
- Emission Inventory Reductions (06-08-2021).xlsx

Appendices
Appendix A– Additional Charts and Figures

We look forward to discussing this report with you in more detail.

Sincerely,

Justin M. Lisowski P.E.
Senior Project Engineer & Facility Specialist
Valor EPC | ph: 303.803.3152 | email: justin.lisowski@valorepc.com

APPENDIX A – ADDITIONAL CHARTS AND FIGURES

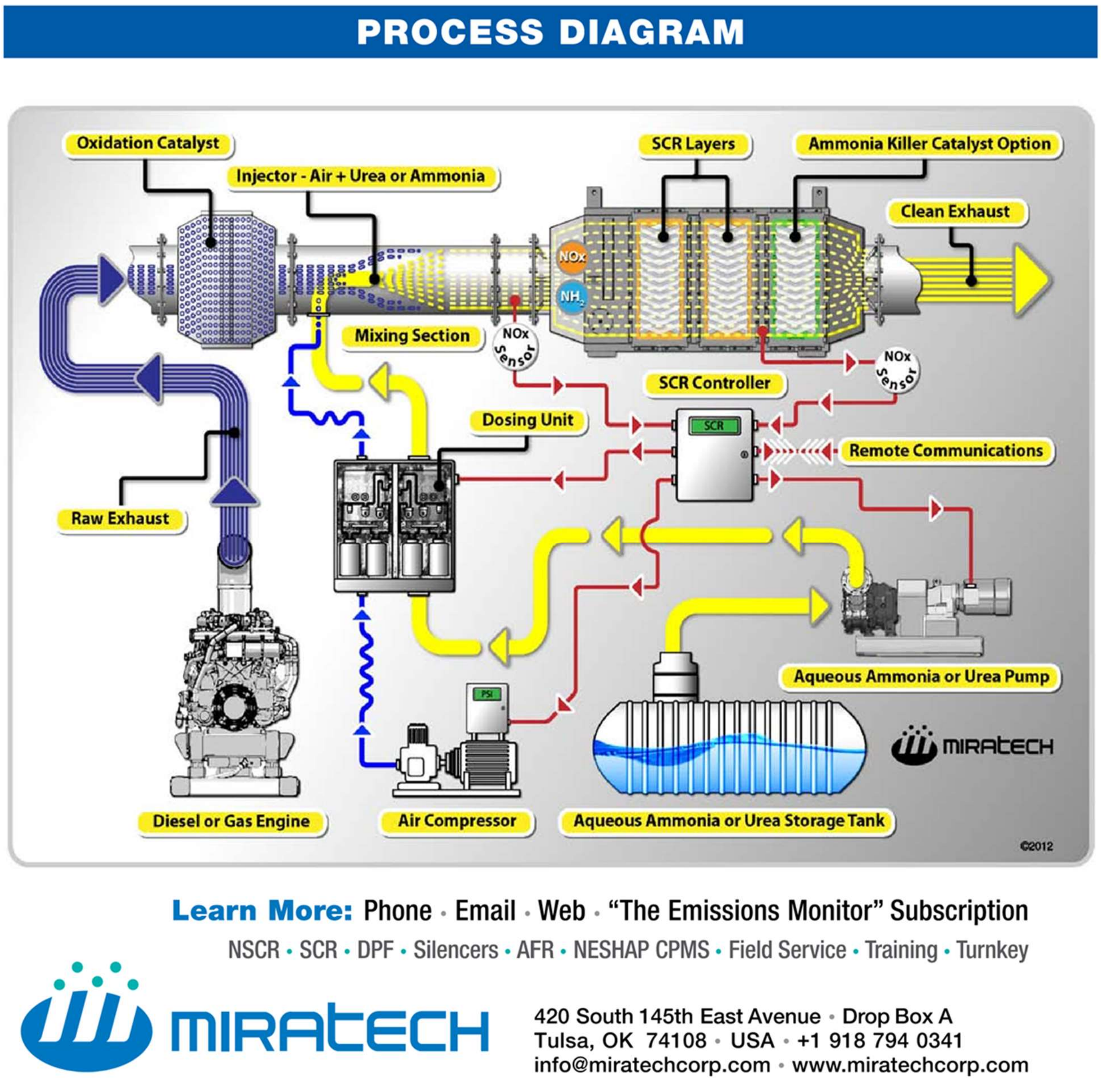

Figure 4: Highlights the complicated nature and significant increase in failure points of SCR system (Source Miratech website)

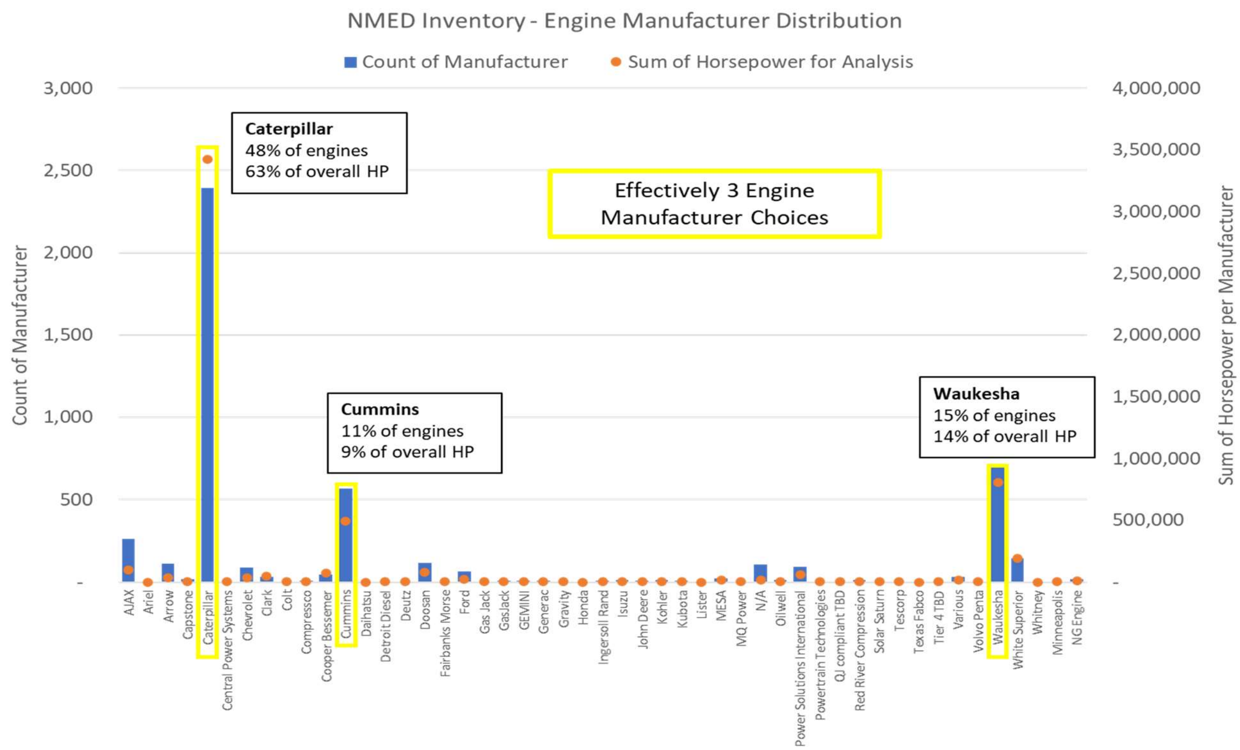

Figure 5: The data in the chart above has been determined to be inaccurate (reference Valor Memo "ERG Engine Inventory Analysis." However, as far as manufacturer distribution, it is assumed to be qualitatively and directionally correct. Source, NMED ICE Reductions and Costs NO2 6-4-21_erg (06-08-2021).xlsx.

Existing Inventory Manufacturer Count (>10% market share)
Caterpillar: 48%
Cummins: 11% (nearly all Cummins are <1000 HP) once errors in NMED HP data are omitted
Waukesha: 15%

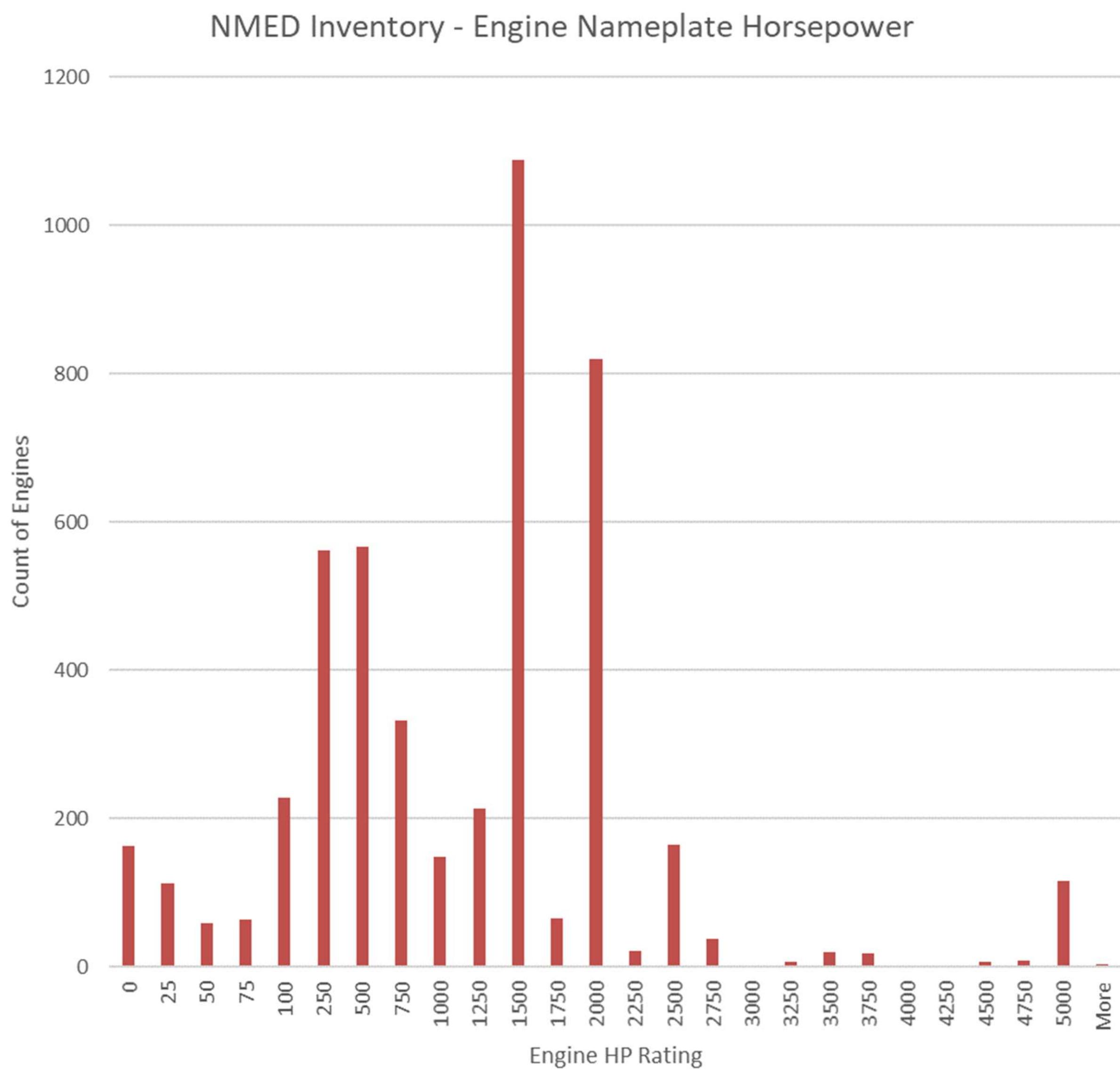

Figure 6: This plot is also from data determined to be inaccurate but provides a qualitative assessment of the amount of inventory that is at risk. Of note, the primary engine selection from ~1250 hp to ~2000 hp is either Waukesha rich burn engines or Caterpillar G3500 series lean burn engines. It is not technically possible for the Caterpillar G3500 engines to meet 0.30 g/hp-hr NOx limit, effectively providing favorable rules to Waukesha as a manufacturer. This further highlights why lean burns should not be given penalizing and disproportionate emission standards to meet. Source, NMED ICE Reductions and Costs NO2 6-4-21_erg (06-08-2021).xlsx (uncorrected).

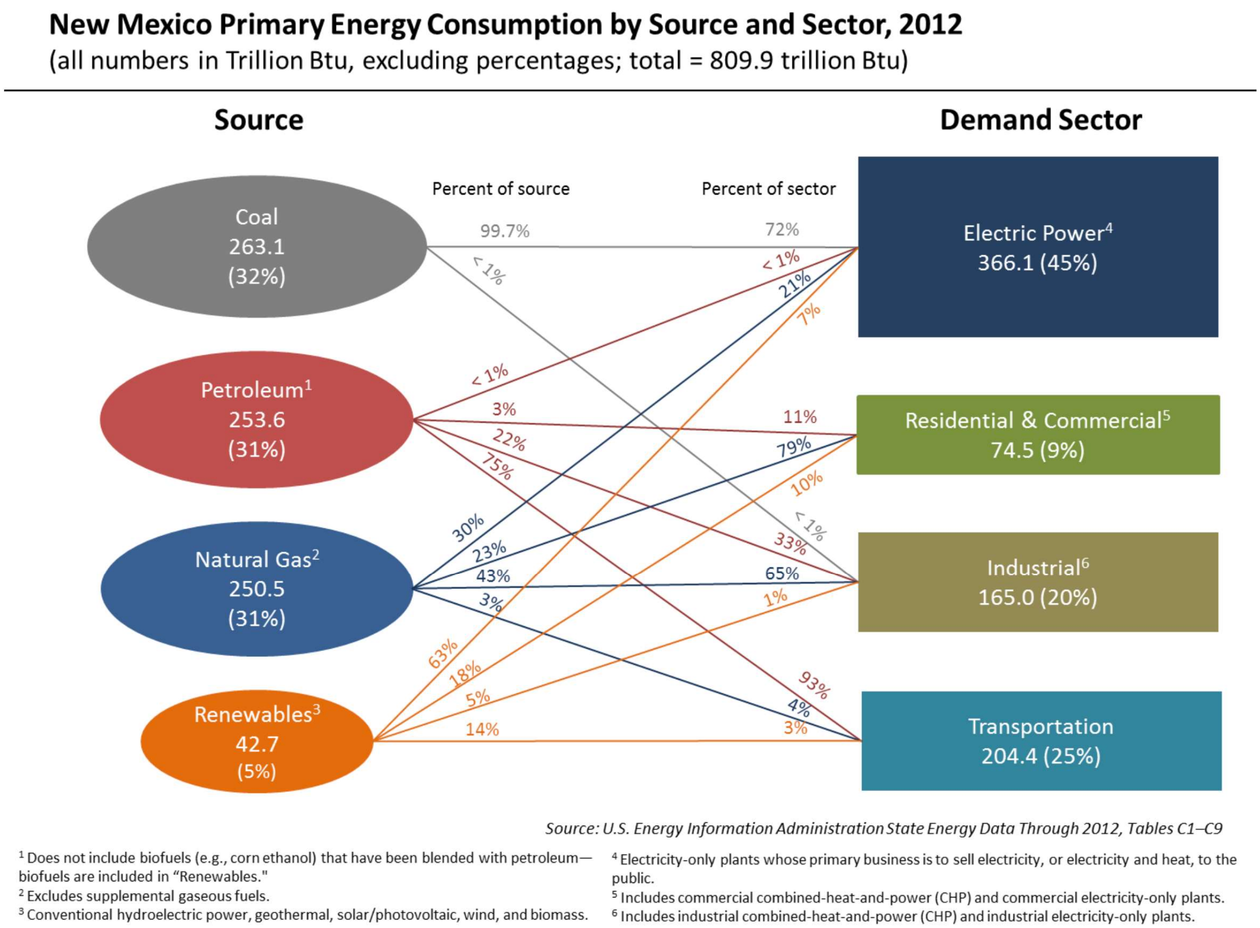

Figure 7: U.S. Energy 2012 study of utilization of energy sources (source US Dept of Energy)

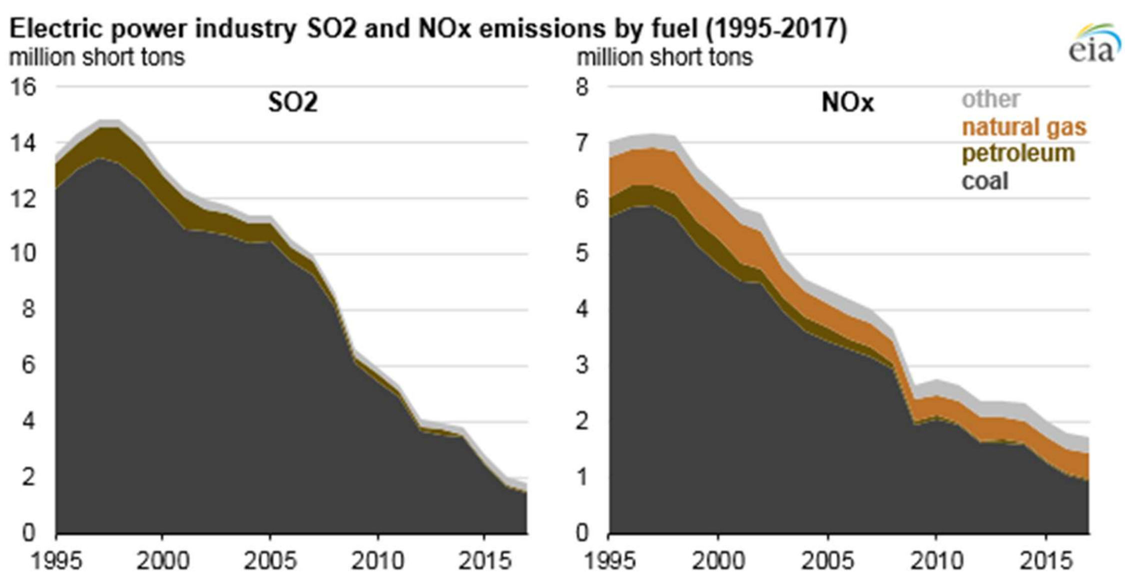

Figure 8: EIA NOx and SO2 as generated by fuel source. (Source EIA)

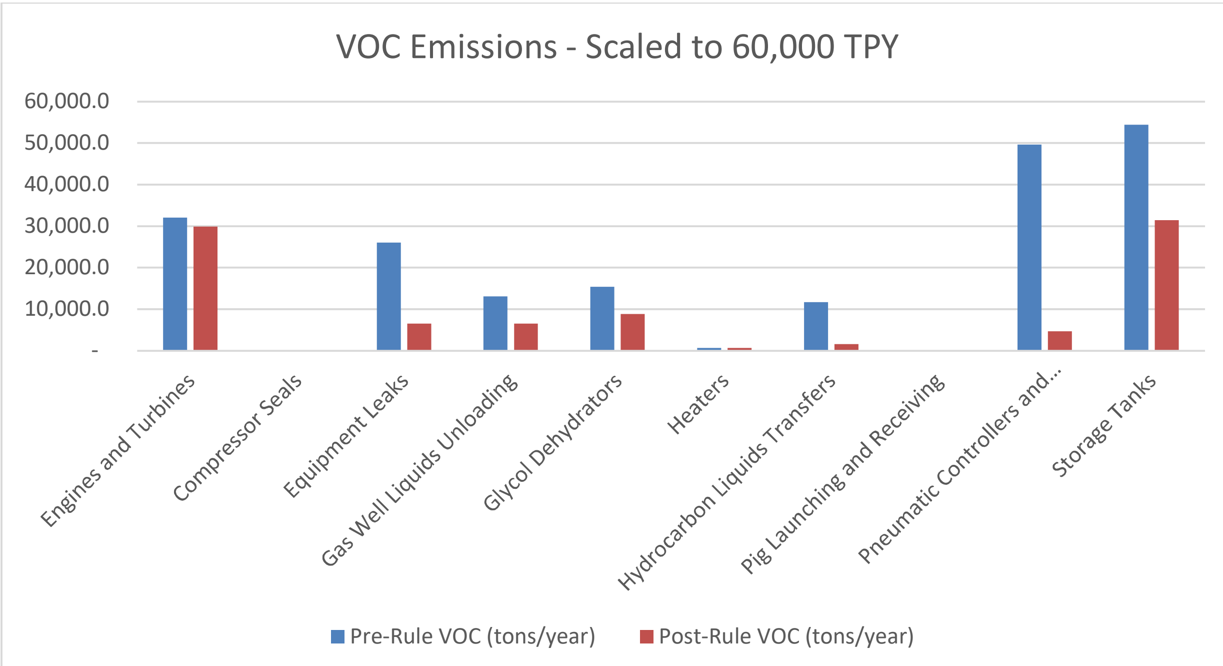

Figure 9: Predicted VOC emissions pre and post rule per NMED/ERG (source Emission Inventory Reductions (06-08-2021).xlsx)

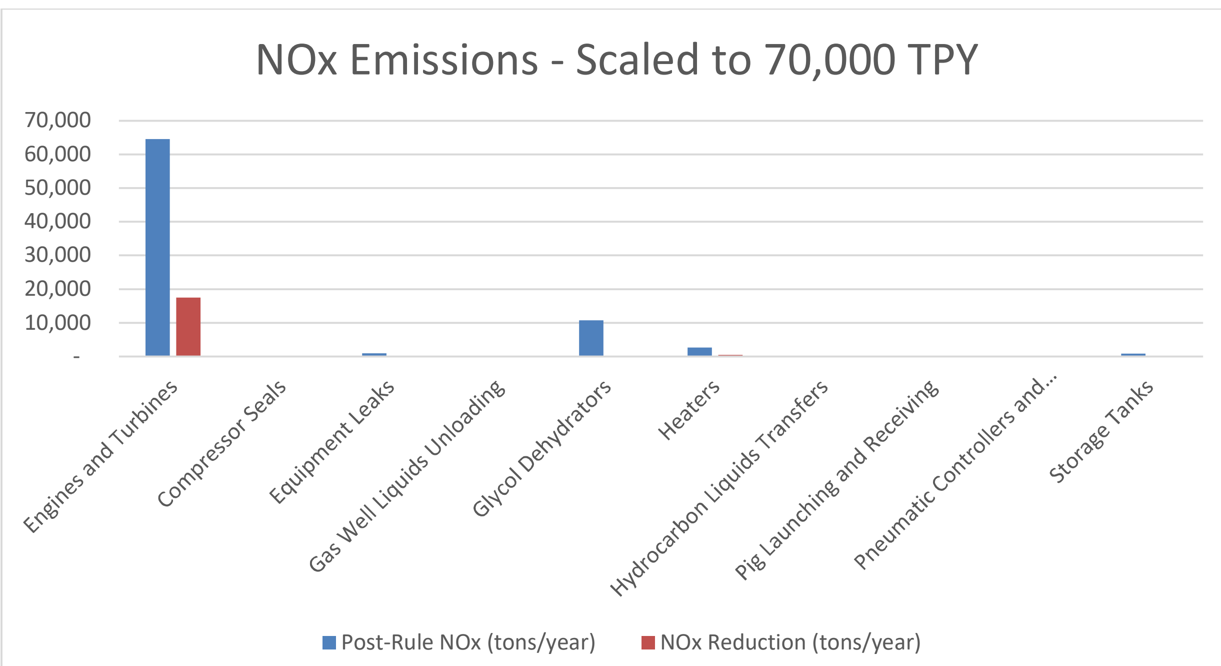

Figure 10: Predicted NOx emissions pre and post rule per NMED/ERG (source Emission Inventory Reductions (06-08-2021).xlsx)

Date 28 July 2021
New Mexico Oil and Gas Association
Attn: John Smitherman

SUBJECT: Valor EPC Study: NMED Engine Inventory Analysis

Dear Mr. Smitherman,

Valor EPC is pleased to provide this study and supporting evidence on the subject of NMED Engine Inventory Analysis as it pertains to Engines and Turbines in response to the proposed rules to Title 20 Chapter 2 Part 50 (20.2.50 NMAC) paragraph 113. The below study represents Valor EPC's professional opinion based on years of experience and supporting data, to the maximum extent possible, within the required schedule.

Executive Summary

New Mexico Environment Department – Air Quality Bureau Equipment Reports (referenced documents #1 and #2)
Valor EPC has reviewed the referenced equipment reports, and have found errors in the reports. Approximately 15% of the input data was found to be in error, and subsequently the NOx tonnage approximations are incorrect
Many of the calculations for both reciprocating internal combustion engines ("ICE") and turbines are based upon column "AC," "Horsepower" and "Horsepower for Analysis" for Turbines (County + Portables Worksheet) and ICE (Counties & Portables), respectively. Valor identified unit conversion errors including kilowatt (kW) to horsepower (HP), fuel gas or compressor flow rates in place of HP, and engine revolutions per minute (RPM) in place of HP. Some examples include multiple instances of Caterpillar G3304 (95 HP units) listed at 1800 HP, Cummins GTA8.3 (175 HP) listed at 1800 HP, and Caterpillar G3608 (~2370 HP) listed at 23,700 HP to list a few.

These errors can be found in in both "ICE Reductions and Costs VOC 6-4-21_erg (06-08-2021R).xlsx" and "ICE Reductions and Costs NO2 6-4-21_erg (06-08-2021).xlsx"

Valor concludes that an accurate analysis of NOX emissions cannot be performed due to errors found in the spreadsheet and significant data processing would be required to calculate the NOX emissions. It should be noted, that Valor did not perform a quality check of the entire datasheet because much of the data cannot be verified by other than the engine owner/operator. Valor EPC reviewed only the "Horsepower" and "Horsepower for Analysis" and identified 738 HP errors (or 15.6%) in these columns alone. Spot checks of these errors also reveal inaccurate NOx tonnage estimates, since these are based upon HP. The errors are identified in the Appendix of this document.

1 References

<u>Referenced NMAC Paragraphs</u>
20.2.50.113

<u>Referenced NMED Documents</u>
The following NMED documents were evaluated (reference https://www.env.nm.gov/air-quality/ozone-precursor-rule-hearing/)

1. ICE Reductions and Costs VOC 6-4-21_erg (06-08-2021R).xlsx
2. ICE Reductions and Costs NO2 6-4-21_erg (06-08-2021).xlsx
3. Turbines Reductions and Costs VOC 6-4-21_erg (06-08-2021).xlsx
4. Turbines Reductions and Costs NO2 6-4-21_erg (06-08-2021).xlsx

We look forward to discussing this report with you in more detail.

Sincerely,

Justin M. Lisowski P.E.
Senior Project Engineer & Facility Specialist
Valor EPC | ph: 303.803.3152 | email: justin.lisowski@valorepc.com

APPENDIX

Errors Identified (highlighted yellow) in NMED "ICE Reductions and Costs VOC 6-4-21_erg (06-08-2021R).xlsx" and "ICE Reductions and Costs NO2 6-4-21_erg (06-08-2021).xlsx"

NMED Column "B"	**NMED Column "AC"**	**Valor Added Column**	**NMED Column "AD"**
AI ID	NMED Horsepower for Analysis (non-corrected)	VALOR EPC Error Note	NOx Output Amount
10	4500		547.5
10	4500		547.5
6	3400		78.8
6	3400		78.8
6	3400		78.8
52	2300		208
14	2250		45.67
14	2250		25.71
27846	1800	rpm not hp	18.4
26135	1800	rpm not hp	15.3
18	1650		63.7
25180	1400		19.4
25180	1400		19.4
19	1265		19.4
19	1265		19.4
18	1232		19
51	1232		19
19	1195		23.99
19	1195		1.96
19	1073		51.8
15	1013		12.7
3458	1000		13.5
51	600		11.6
19	600		2.9
29286	563		16.2
24847	550		15.9
58	530		10.24
26629	530		7.3
22	530		5.1
58	440		15.5
58	440		15.5

14	425		4.1
14	425		4.1
10	408		27
22	316		14.6
24847	265		7.7
8	203		32.48
44	124		11.39
29	97		14.89
26720	7553	units listed as rpm, actually BTU/hr, both not hp	14.5
38780	5000		24.14
39194	5000		18.11
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38646	5000		15.21
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38912	3750		10.86
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38912	3750		10.86
38912	3750		10.86
38771	2722		85.29
39172	2722		85.29
39194	2675		9.69
39194	2675		9.69
39194	2675		9.69
39194	2675		9.69
203	2650		47.98
31001	2650		38.4
38692	2600	rpm not hp	2.79
35289	2500		16.5

38977	2500		15.09
38977	2500		15.09
38977	2500		15.09
38977	2500		15.09
38977	2500		15.09
38418	2500		14.5
38418	2500		14.5
39029	2500		12.1
39029	2500		12.1
39029	2500		12.1
39029	2500		12.1
39029	2500		12.1
38055	2500		12.1
38563	2500		12.07
39294	2500		12.07
39294	2500		12.07
39294	2500		12.07
39294	2500		12.07
39294	2500		12.07
39294	2500		12.07
36954	2500		9.66
36954	2500		9.66
39540	2500		9.1
39540	2500		9.1
39049	2500		9.05
39049	2500		9.05
39049	2500		9.05
39141	2500		9.04
39141	2500		9.04
39141	2500		9.04
39141	2500		9.04
39141	2500		9.04
39141	2500		9.04
39141	2500		9.04
39455	2500		9
39455	2500		9
39455	2500		9
39455	2500		9
39455	2500		9
39455	2500		9
39455	2500		9
39455	2500		9
39287	2500		7.24
38912	2500		7.23

38912	2500		7.23
32117	2500		7.2
32117	2500		7.2
32117	2500		7.2
32117	2500		7.2
32117	2500		7.2
32117	2500		7.2
32117	2500		7.2
32117	2500		7.2
39000	2500		7.18
39000	2500		7.18
39000	2500		7.18
39141	2500		1.34
32575	2370		11.4
36133	2250		13.58
36133	2250		13.58
36133	2250		13.58
36133	2250		13.58
38774	2059		85.29
483	2000		36.7
37920	2000	rpm not hp	2.6
38301	2000	rpm not hp	2.6
38301	2000	rpm not hp	2.6
32575	1980		37.3
38815	1950		9.42
227	1900		64.2
227	1900		64.2
38046	1900		18.3
37931	1900		9.2
38519	1900		9.2
38519	1900		9.2
38519	1900		9.2
38519	1900		9.2
39180	1881		9.99
39180	1881		9.99
39180	1881		9.99
39180	1881		9.99
37882	1881		9.1
37882	1881		9.1
37882	1881		9.1
38721	1878		9.05
38721	1878		9.05
38721	1878		9.05
33561	1875		14.28

33561	1875		14.28
33561	1875		14.28
33561	1875		14.28
33561	1875		14.28
33561	1875		14.28
33561	1875		14.28
33561	1875		14.28
35289	1875		13
35289	1875		13
35289	1875		13
35289	1875		13
35289	1875		13
39340	1875		11.3
39340	1875		11.3
39340	1875		11.3
39340	1875		11.3
39340	1875		11.3
39560	1875		11.3
39560	1875		11.3
39560	1875		11.3
39560	1875		11.3
39540	1875		11.3
38198	1875		10.36
38198	1875		10.36
38198	1875		10.36
38198	1875		10.36
38198	1875		10.36
38198	1875		10.36
38198	1875		10.36
38198	1875		10.36
38836	1875		9.1
38836	1875		9.1
38836	1875		9.1
37921	1875		9.1
29339	1875		9.1
38618	1875		9.1
37874	1875		9.1
38069	1875		9.1
38069	1875		9.1
38069	1875		9.1
37959	1875		9.1
37959	1875		9.1
37874	1875		9.1
37959	1875		9.1

37959	1875		9.1
37959	1875		9.1
37959	1875		9.1
38069	1875		9.1
38069	1875		9.1
38340	1875		9.1
38340	1875		9.1
31381	1875		9.1
31381	1875		9.1
39255	1875		9.05
39255	1875		9.05
39255	1875		9.05
39000	1875		9.05
39000	1875		9.05
39000	1875		9.05
39320	1875		9.05
39320	1875		9.05
39320	1875		9.05
39320	1875		9.05
37772	1875		9.05
37772	1875		9.05
38618	1875		9.05
39287	1875		9.05
39287	1875		9.05
39287	1875		9.05
39287	1875		9.05
39025	1875		9.05
39025	1875		9.05
39025	1875		9.05
38618	1875		9.05
38618	1875		9.05
37991	1875		8.6
37991	1875		8.6
37991	1875		8.6
36430	1863		8.99
39180	1862		12.59
36430	1836		8.99
3415	1800	rpm not hp	24.5
24766	1800	rpm not hp	19.3
28179	1800	rpm not hp	15.3
30089	1800	rpm not hp	15.1
27896	1800	rpm not hp	14.8
27898	1800	rpm not hp	14.8
27906	1800	rpm not hp	14.8

27897	1800	rpm not hp	14.8
24382	1800	rpm not hp	14.5
24360	1800	rpm not hp	14.5
25392	1800	rpm not hp	14.5
25394	1800	rpm not hp	14.5
25393	1800	rpm not hp	14.5
24578	1800	rpm not hp	13.6
24106	1800	rpm not hp	11.8
28654	1800	rpm not hp	10.6
28234	1800	rpm not hp	10.1
24804	1800	rpm not hp	7.4
39514	1800	rpm not hp	5.6
39547	1800	rpm not hp	5.6
39547	1800	rpm not hp	5.6
39547	1800	rpm not hp	5.6
39482	1800	rpm not hp	5.3
39482	1800	rpm not hp	5.3
35405	1800	rpm not hp	3.9
38612	1800	rpm not hp	3.9
29635	1800	rpm not hp	3.9
39547	1800	rpm not hp	3.8
38731	1800	rpm not hp	3.7
39230	1800	rpm not hp	3.7
39417	1800	rpm not hp	3.67
39482	1800	rpm not hp	3.5
32718	1800	rpm not hp	2.8
31803	1800	rpm not hp	2.67
38301	1800	rpm not hp	2.63
39400	1800	rpm not hp	2.6
39417	1800	rpm not hp	2.6
39418	1800	rpm not hp	2.6
38731	1800	rpm not hp	2.6
38731	1800	rpm not hp	2.6
38731	1800	rpm not hp	2.6
39230	1800	rpm not hp	2.6
39230	1800	rpm not hp	2.6
39027	1800	rpm not hp	2.59
38731	1800	rpm not hp	2.5
39417	1800	rpm not hp	2.5
39418	1800	rpm not hp	2.5
39400	1800	rpm not hp	2.5
38164	1800	rpm not hp	2.4
39547	1800	rpm not hp	2.3
39547	1800	rpm not hp	2.3

38692	1800	rpm not hp	2.2
38692	1800	rpm not hp	2.2
35932	1800	rpm not hp	2.1
38613	1800	rpm not hp	2
38613	1800	rpm not hp	2
37868	1800	rpm not hp	2
38731	1800	rpm not hp	2
39417	1800	rpm not hp	1.96
37920	1800	rpm not hp	1.92
38069	1800	rpm not hp	1.9
39400	1800	rpm not hp	1.9
39417	1800	rpm not hp	1.9
39418	1800	rpm not hp	1.9
39230	1800	rpm not hp	1.9
37978	1800	rpm not hp	1.8
39514	1800	rpm not hp	1.8
38492	1800	rpm not hp	1.7
38492	1800	rpm not hp	1.7
38744	1800	rpm not hp	1.7
35292	1800	rpm not hp	1.4
39563	1800	rpm not hp	1.1
39563	1800	rpm not hp	1.1
39563	1800	rpm not hp	1.1
39563	1800	rpm not hp	1.1
39564	1800	rpm not hp	1.1
39564	1800	rpm not hp	1.1
20489	1800	rpm not hp	1.1
28953	1800	rpm not hp	0.6
28953	1800	rpm not hp	0.6
30070	1800	rpm not hp	0.6
39540	1800	rpm not hp	0.5
37868	1800	rpm not hp	0.3
38245	1800	rpm not hp	0.023
36953	1775		13.2
36953	1775		13.2
37808	1775		12
39024	1775		12
39024	1775		12
417	1775		12
39018	1775		12
417	1775		12
417	1775		12
38210	1775		10.8
38210	1775		10.8

38210	1775		10.8
38210	1775		10.8
37808	1775		8.6
37808	1775		8.6
37808	1775		8.6
37808	1775		8.6
37808	1775		8.6
39024	1775		8.6
38782	1775		8.6
38004	1775		8.6
38004	1775		8.6
38004	1775		8.6
38782	1775		8.6
38782	1775		8.6
38782	1775		8.6
38056	1775		8.6
38232	1775		8.6
38790	1775		8.6
38791	1775		8.6
38798	1775		8.6
38800	1775		8.6
38803	1775		8.6
37991	1775		8.6
37991	1775		8.6
37991	1775		8.6
37991	1775		8.6
38069	1775		8.6
37965	1775		8.6
38024	1775		8.6
38024	1775		8.6
38024	1775		8.6
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38024	1775		8.6
38024	1775		8.6
38024	1775		8.6
38024	1775		8.6
38027	1775		8.6
38027	1775		8.6
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38027	1775		8.6
38027	1775		8.6
38027	1775		8.6
38027	1775		8.6

38341	1775		8.57
38341	1775		8.57
38341	1775		8.57
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38341	1775		8.57
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38341	1775		8.57
38341	1775		8.57
38341	1775		8.57
38215	1775		8.57
38055	1775		8.57
38055	1775		8.57
38149	1775		8.57
38274	1775		8.57
39018	1775		8.57
39018	1775		8.57
38205	1775		8.56
38205	1775		8.56
38205	1775		8.56
38205	1775		8.56
38432	1775		8.56
38432	1775		8.56
38432	1775		8.56
38432	1775		8.56
29606	1775		8.55
410	1775		8.3
410	1775		8.3
27667	1775		8.3
27667	1775		8.3
31115	1725		8.3
24315	1725		8.3
24315	1725		8.3
31115	1725		6.7
38843	1680		32.9
34430	1680		16.223
34430	1680		16.223
32575	1680		16.2
32575	1680		16.2

38843	1680		15.2
38843	1680		15.2
39196	1680		10.2
32662	1680		10.1
37964	1680		8.2
37882	1680		8.1
37882	1680		8.1
37882	1680		8.1
37882	1680		8.1
38046	1680		8.1
38046	1680		8.1
38046	1680		8.1
32662	1680		8.1
37931	1680		8.1
37931	1680		8.1
37931	1680		8.1
37931	1680		8.1
410	1665		12.89
410	1665		12.89
410	1665		12.89
410	1665		12.89
410	1665		12.89
20489	1665		11.2
20489	1665		11.2
2418	1547		29.9
26896	1547		22.4
26896	1547		22.4
21848	1500	rpm not hp	18.3
25116	1500	rpm not hp	18.3
199	1480		37.7
36086	1480		14.29
36086	1480		14.29
36086	1480		14.29
36086	1480		14.29
30051	1480		14.15
30051	1480		14.15
30051	1480		14.15
30051	1480		14.15
266	1478		21.4
266	1478		21.4
203	1478		17.84
29771	1478		14.3
29771	1478		14.3
29771	1478		14.3

31977	1478		12.8
31977	1478		12.8
413	1478		12.58
413	1478		12.5
413	1478		12.5
413	1478		12.5
307	1478		12.49
307	1478		12.49
27667	1478		11.6
27667	1478		11.6
27667	1478		11.6
27667	1478		11.6
27667	1478		11.6
27667	1478		11.6
27667	1478		11.6
27667	1478		11.6
30964	1478		10
30964	1478		10
30964	1478		10
30519	1478		9.3
30519	1478		9.3
30519	1478		9.3
30519	1478		9.3
35452	1400	rpm not hp	27.4
37965	1400		26
35485	1400	rpm not hp	25.9
37964	1400	rpm not hp	25.9
37964	1400	rpm not hp	25.9
483	1400		25.9
35929	1400		25.88
35485	1400	rpm not hp	25.88
381	1400	rpm not hp	25.88
381	1400	rpm not hp	25.88
4596	1400	rpm not hp	25.88
4596	1400		25.88
38245	1400	rpm not hp	25.87
34085	1400		24.4
439	1400	rpm not hp	24.4
443	1400	rpm not hp	24.4
443	1400	rpm not hp	24.4
443	1400	rpm not hp	24.4
448	1400	rpm not hp	24.4
439	1400	rpm not hp	24.4
439	1400	rpm not hp	24.4

448	1400	rpm not hp	24.4
443	1400	rpm not hp	24
24977	1400	rpm not hp	24
24977	1400	rpm not hp	24
37964	1400		21
24977	1400		19.4
3432	1400		19.4
38301	1400		13.33
38301	1400		13.33
37920	1400		13.33
37920	1400		13.33
32449	1400		13.3
32449	1400		13.3
32449	1400		13.3
32449	1400		13.3
38395	1400		13.3
31720	1400		13.3
31720	1400		13.3
35781	1400		13.3
35781	1400		13.3
38395	1400		13.3
24106	1400		13.1
24106	1400		13.1
24106	1400		13.1
34955	1400		12.83
34955	1400		12.8
353	1400		12.2
337	1400		9.9
35583	1400		8.4
35583	1400		8.4
35583	1400		8.4
35583	1400		8.4
34002	1400		8.33
34002	1400		8.33
34002	1400		8.33
34002	1400		8.33
37596	1400		8.32
37596	1400		8.32
38245	1400		8.32
38071	1400		8.3
410	1400		8.3
410	1400		8.3
38290	1400		8.3
39514	1400		8.3

38290	1400		8.3
38290	1400		8.3
38290	1400		8.3
37954	1400		8.09
37954	1400		8.08
37954	1400		8.08
37954	1400		8.08
37954	1400		8.08
31115	1400		6.7
29606	1400		6.7
31115	1400		6.7
31115	1400		6.7
266	1400		6.7
266	1400		6.7
38492	1400		6.7
38492	1400		6.7
38492	1400		6.7
38492	1400		6.7
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38492	1400		6.7
38492	1400		6.7
38492	1400		6.7
38492	1400		6.7
38492	1400		6.7
37921	1400		6.7
37921	1400		6.7
31472	1400		6.7
31472	1400		6.7
31472	1400		6.7
29339	1400		6.7
29339	1400		6.7
29339	1400		6.7
37921	1400		6.7
31720	1400		6.7
31720	1400		6.7
37874	1400		6.7
37874	1400		6.7
39547	1400		6.7
37965	1400		6.7
417	1400		6.7
417	1400		6.7
37874	1400		6.7
37874	1400		6.7
37965	1400		6.7

38340	1400		6.7
38340	1400		6.7
38340	1400		6.7
38340	1400		6.7
39547	1400		6.7
32575	1400		6.7
38301	1400		6.66
39322	1400		6.66
38340	1400		3.2
38340	1400		3.2
38245	1400		0.88
32662	1380		26.7
38142	1380		26.7
38127	1380		26.7
32662	1380		26.7
32668	1380		26.7
32668	1380		26.7
32668	1380		26.7
32662	1380		26.7
378	1380		24.3
378	1380		24.3
38414	1380		16.66
36618	1380		15.31
38372	1380		13.33
38117	1380		13.33
39610	1380		13.33
39610	1380		13.33
38058	1380		13.33
38563	1380		13.33
31815	1380		13.32
31815	1380		13.32
29771	1380		13.3
38122	1380		13.3
38348	1380		13.3
38348	1380		13.3
38348	1380		13.3
38348	1380		13.3
38348	1380		13.3
38636	1380		13.3
38636	1380		13.3
38636	1380		13.3
38636	1380		13.3
29329	1380		13.3
29329	1380		13.3

31692	1380		13.3
31692	1380		13.3
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31692	1380		13.3
31692	1380		13.3
31692	1380		13.3
38946	1380		13.3
34001	1380		13.3
34001	1380		13.3
34001	1380		13.3
391	1380		12.98
37808	1380		12
30070	1380		10.7
30070	1380		10.7
30070	1380		10.7
30070	1380		10.7
30070	1380		10.7
30070	1380		10.7
37951	1380		9.99
33561	1380		9.56
33561	1380		9.56
33561	1380		9.56
33561	1380		9.56
38790	1380		8.6
38790	1380		8.6
38420	1380		8.4
38420	1380		8.4
36793	1380		8.33
39489	1380		8.33
38191	1380		8.33
39001	1380		8.33
39001	1380		8.33
39001	1380		8.33
39001	1380		8.33
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39001	1380		8.33
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39001	1380		8.33
39001	1380		8.33
38455	1380		8.33
38455	1380		8.33
263	1380		8.33
263	1380		8.33

39582	1380		8.33
39582	1380		8.33
39582	1380		8.33
39582	1380		8.33
39582	1380		8.33
39582	1380		8.33
30051	1380		8.33
30051	1380		8.33
39194	1380		8.33
39194	1380		8.33
38927	1380		8.32
38927	1380		8.32
38927	1380		8.32
38927	1380		8.32
38683	1380		8.32
38683	1380		8.32
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38683	1380		8.32
38683	1380		8.32
39560	1380		8.32
38414	1380		8.32
38156	1380		8.32
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38156	1380		8.32
38156	1380		8.32
38826	1380		8.32
38826	1380		8.32
38323	1380		8.32
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38826	1380		8.32
38826	1380		8.32
38831	1380		8.32
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38826	1380		8.32
38508	1380		8.32
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38508	1380		8.32
38508	1380		8.32

38508	1380		8.32
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38832	1380		8.32
38832	1380		8.32
31115	1380		8.3
31115	1380		8.3
38071	1380		8.3
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38418	1380		7.99
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38418	1380		7.99
37808	1380		6.7
37808	1380		6.7
38563	1380		6.7
38563	1380		6.7
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38563	1380		6.7
31115	1380		6.7
38836	1380		6.7
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38836	1380		6.7
37991	1380		6.7
38056	1380		6.7
38056	1380		6.7
38232	1380		6.7
38232	1380		6.7
38791	1380		6.7
38791	1380		6.7
38618	1380		6.7
38024	1380		6.7
38027	1380		6.7
31381	1380		6.7
31381	1380		6.7
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31381	1380		6.7
37947	1380		6.66
38170	1380		6.66
38327	1380		6.66
38170	1380		6.66
37947	1380		6.66
37945	1380		6.66
36954	1380		6.66
36954	1380		6.66
479	1380		6.66
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38128	1380		6.66
38128	1380		6.66
38128	1380		6.66
38128	1380		6.66
38215	1380		6.66
38215	1380		6.66
39321	1380		6.66
39321	1380		6.66
39357	1380		6.66
39551	1380		6.66
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38149	1380		6.66
38274	1380		6.66
38274	1380		6.66
38798	1380		6.66
38798	1380		6.66
38800	1380		6.66
38800	1380		6.66

39012	1380		6.66
39012	1380		6.66
37772	1380		6.66
37772	1380		6.66
39545	1380		6.66
39195	1380		6.66
38825	1380		6.66
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38842	1380		6.66
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39358	1380		6.66
38835	1380		6.66
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39164	1380		6.66
38826	1380		4.16
38215	1380		3.92
38826	1380		2.77
38803	1380		1.52
38803	1380		1.52
38408	1380		0.285
38618	1375		6.7
38618	1375		6.66
266	1360		13.3
199	1340		25.9

26896	1340		25.9
199	1340		25.9
26896	1340		25.9
199	1340		25.9
199	1340		25.9
199	1340		25.9
409	1340		25.9
37940	1340		25.9
39055	1340		25.88
39055	1340		25.88
31815	1340		25.88
37946	1340		25.88
36954	1340		25.88
36954	1340		25.88
39017	1340		25.88
39017	1340		25.88
32886	1340		25.88
34430	1340		25.88
29329	1340		24.3
29329	1340		24.3
29329	1340		24.3
29329	1340		24.3
378	1340		24.3
36953	1340		21.4
408	1340		20.95
33602	1340		19.41
33602	1340		19.41
27765	1340		19.4
27765	1340		19.4
33200	1340		19.4
191	1340		19.4
191	1340		19.4
191	1340		19.4
191	1340		19.4
191	1340		19.4
27765	1340		19.4
36370	1340		19.4
36370	1340		19.4
3455	1340		19.4
31426	1340		19.4
38058	1340		12.94
37957	1340		12.94
38222	1340		12.94
38222	1340		12.94

37940	1340		6.7
39545	1340		6.47
37957	1340		6.47
37979	1340		6.46
37979	1340		6.46
37979	1340		6.46
37979	1340		6.46
37928	1318		6.36
261	1265		41.2
237	1265		26.8
354	1265		24.4
354	1265		24.4
39270	1265		24.4
39270	1265		24.4
29537	1265		24.4
29537	1265		24.4
29537	1265		24.4
29537	1265		24.4
337	1265		24.4
391	1232		64.12
3432	1232		23.8
374	1232		23.8
314	1232		19.3
314	1232		19.2
414	1232		19
4596	1215		23.46
483	1200		30.2
295	1200		30.18
380	1200	rpm not hp	29.7
380	1200	rpm not hp	29.7
380	1200	rpm not hp	29.7
2038	1200	rpm not hp	27.7
261	1200	rpm not hp	24
3432	1200		22.2
3432	1200		22.2
24105	1200		22
26314	1200		8.8
268	1200		5.2
26896	1151		16.7
26896	1151		16.7
26896	1151		16.7
335	1150		22.2
488	1085		20.95
408	1085		20.95

408	1085		20.95
408	1085		20.95
415	1085		19.91
415	1085		19.91
26896	1085		15.7
414	1073		51.8
34430	1050		20.28
34430	1050		20.28
289	1037	wrong units, no HP, but large Nox contribution	14.52
204	1024		24.3
251	1024		15.8
252	1024		12
29121	1005		19.4
29272	1005		19.4
34970	1005		14.5
30476	1005		9.68
27247	1004		19.35
302	1000		19.7
302	1000		19.7
374	1000		14.1
23563	1000	rpm not hp	13.2
199	900		23.2
374	900		23.18
241	900		21.7
241	900		21.7
241	900		21.7
302	900		19.3
291	900		19.3
302	900		19.3
302	900		19.3
260	900		17.37
252	900		13.1
251	900		12.2
252	900		12
35784	860		15.6
261	830		24
404	814		15.69
3432	814		15.69
38780	805		0.39
209	800		23.2
242	800		23.2
209	800		23.2
242	800		23.2

255	800		23.2
199	800		23.2
199	800		23.2
199	800		23.2
199	800		23.2
199	800		23.2
199	800		23.2
199	800		23.2
199	800		23.2
199	800		23.2
255	800		23.2
199	800		23.2
255	800		23.2
255	800		23.2
241	800		21.7
374	800		15.5
214	800		15.5
252	800		13.1
252	800		13.1
252	800		13.1
252	800		13.1
251	800		12.2
251	800		12.2
251	800		12.2
251	800		12.2
251	800		12.2
251	800		12.2
251	800		12.2
251	800		12.2
251	800		12.2
251	800		12.2
25917	800		3.3
204	785		24.3
207	785		21
37946	760		7.34
39322	760		7.34
39357	760		7.34
39195	760		7.34
39358	760		7.34
37872	738		7.1
37872	738		7.1
37872	738		7.1
242	732		21.2
34184	700		6.76

38541	690		6.77
37872	690		6.7
37872	690		6.7
37872	690		6.7
38165	690		6.67
39610	690		6.66
37803	690		6.66
38926	690		4.2
39532	690		4.2
36619	690		4.16
39288	690		4.16
39212	690		4.16
39212	690		4.16
39357	690		3.33
36845	690		3.33
39195	690		3.33
39011	690		3.33
39011	690		3.33
39322	690		3.33
39358	690		3.33
38912	684		6.61
38912	684		6.61
38420	684		6.6
39380	684		6.6
38414	684		0.05
39453	684		0.04
39453	684		0.04
39453	684		0.04
39453	684		0.04
39453	684		0.04
39453	684		0.04
39453	684		0.04
39453	684		0.04
39453	684		0.04
38915	684		0.002
38915	684		0.002
38915	684		0.002
38915	684		0.002
38915	684		0.002
38915	684		0.002
38915	684		0.002
38915	684		0.002
38915	684		0.002
38529	676		1.56

230	675		18.4
230	675		18.4
230	675		18.4
263	675		7.7
263	675		7.7
263	675		7.7
263	675		7.7
38205	674		3.3
38205	674		3.25
35912	671		2.1
38715	670		3.2
38715	670		3.2
374	667		15.5
242	650		18.8
39290	650		6.28
39285	650		0.47
39164	650		0.38
377	640		8.03
29591	633		12.2
29573	633		12.2
29631	633		12.2
29704	630		12.1
39538	630		6.08
39538	630		6.08
33387	607		16.9
26779	607		12.9
355	600		11.6
36619	600		5.79
39212	600		3.62
39212	600		3.62
38218	590		5.6
38218	590		5.6
39545	581		5.61
39545	581		5.61
39532	581		5.61
39551	581		5.61
39023	581		5.61
39023	581		5.61
39023	581		5.61
39023	581		5.61
39023	581		5.61
39023	581		5.61
38117	581		5.61
39027	581		5.61

39027	581		5.61
38218	581		5.6
38454	581		5.6
38454	581		5.6
38454	581		5.6
38541	581		5.6
38117	581		1.4
29814	563		16.2
30000	563		16.2
29330	563		16.2
39480	550		5.31
39536	550		5.31
39536	550		5.31
39495	550		5.31
39496	550		5.31
38398	550		5.31
38398	550		5.31
39295	550		5.31
39295	550		5.31
38648	550		5.3
38648	550		5.3
38845	550		5.3
38845	550		5.3
38844	550		5.3
38844	550		5.3
38704	550		5.3
38848	550		5.3
38848	550		5.3
39193	550		5.3
38636	550		0.159
38636	550		0.159
38636	550		0.159
383	540		10.39
268	538		10.9
268	538		10.9
38117	530		10.24
35715	530		2.53
35715	530		2.53
27842	525		1.8
26896	515		10
38565	515		9.9
38925	500		17.52
299	500		9.6
299	500		9.6

38487	479		4.63
38487	479		4.63
38487	479		4.63
38487	479		4.63
38487	479		4.63
38487	479		4.63
38487	479		4.63
38487	479		4.63
38500	479		4.63
38500	479		4.63
30089	475		2.5
39489	469		4.53
38533	451		0.06
39582	449		0.3
29404	448		16.2
207	440		11.8
33688	440		7.4
28451	440		7.4
29615	440		7.4
34184	425		8.21
28300	425		4.3
29884	422		19.4
29890	422		19.3
409	415		8
3407	400		24.7
24895	400		24.7
3421	400		24.7
24721	400		10.5
28258	400		10.5
20173	400		9.5
4640	400		9.5
4640	400		6.3
38506	400		3.9
38506	400		3.9
38326	400		3.86
39610	400		3.86
39285	400		3.86
39290	400		3.86
39290	400		3.86
39380	400		3.86
38565	390		3.8
38339	390		3.8
38541	390		3.8
39168	390		3.77

39362	390		3.77
39027	390		3.77
39027	390		3.77
38410	390		3.77
39288	390		0.007
4702	384		7.42
38595	380		4.59
38218	380		3.7
38218	380		3.7
38339	380		3.7
39168	380		3.67
39418	380		3.67
37181	380		3.67
37181	380		3.67
37804	380		3.67
37868	380		3.67
39043	380		3.67
39362	380		3.67
39362	380		3.67
37803	380		3.67
37373	380		3.67
38529	380		3.67
38533	380		3.67
37387	380		3.67
38615	380		3.67
36979	380		3.67
36979	380		3.67
38410	380		3.67
37957	380		3.67
38246	380		3.67
38246	380		3.67
37421	380		3.67
37662	380		1.84
38400	380		1.84
38530	380		1.84
38087	380		1.84
38087	380		1.84
38692	380		1.84
37042	380		1.8
37181	380		1.06
207	365		9.8
207	365		9.8
207	365		9.8
28618	364		7.03

VALOR EPC

476	364		6.7
38499	364		3.51
38499	364		3.51
38499	364		3.5
39495	362		3.5
39496	362		3.5
38704	362		3.5
38704	362		3.5
38848	362		3.5
39193	362		3.5
38701	362		3.5
39295	362		3.5
39295	362		3.5
324	360		15.6
21972	360		12.72
27606	360		9.8
4640	360		8.8
306	360		6.96
351	360		6.53
455	360		6.4
37928	360		1.91
37928	360		1.91
32861	347		8.1
376	346		21.1
35492	302		2.9
35492	302		2.9
35492	302		2.9
35644	302		2.9
351	300		10.89
398	300		8.39
288	300		5.78
272	300		5.19
36979	282		0.08
38529	282		0.08
38615	282		0.08
420	276		20.2
372	276		20.2
31539	276		5.33
38977	276		1.67
39001	276		1.67
38071	276		1.67
39480	272		2.63
36954	272		2.63
36954	272		2.63

37972	272		2.63
37972	272		2.63
39410	272		2.63
39410	272		2.63
39410	272		2.63
39410	272		2.63
39410	272		2.63
38122	272		2.6
38122	272		2.6
38122	272		2.6
36953	272		2.6
36953	272		2.6
38565	268		2.6
38218	268		2.6
38454	268		2.6
38339	268		2.6
38339	268		2.6
39168	268		2.59
39043	268		2.59
39043	268		2.59
39043	268		2.59
39362	268		2.59
39362	268		2.59
38327	268		2.59
38926	268		1.92
34714	256		6.28
38782	256		0.5
35715	256		0.49
35715	256		0.49
36954	256		0.42
281	255		24.1
304	251		13.52
29283	240		16.2
29285	240		12.9
28646	240		10.6
28647	240		10.6
28812	240		6.9
28300	240		6.9
28792	240		6.9
268	240		4.6
38595	236		2.28
38055	236		0.02
38055	236		0.02
308	233		11

309	233		11
462	230		6.65
38530	225		2.17
510	221		6.4
510	221		6.4
412	221		6
35880	215		2.1
36171	215		2.1
37803	215		2.08
39185	211		2.04
39185	211		2.04
39185	211		2.04
39185	211		2.04
36965	211		2
33052	210		2.5
33052	210	wrong units, no HP, but large Nox contribution	2.5
39610	205		1.98
37286	203		13.3
35990	203		7.2
38565	203		5.9
38341	203		3.92
31476	203		3.92
38274	203		3.92
38455	203		3.92
38149	203		3.92
38798	203		3.92
35062	203		3.9
38056	203		3.9
38232	203		3.9
38790	203		3.9
38791	203		3.9
38800	203		3.9
38803	203		3.9
38024	203		3.9
38027	203		3.9
37042	203		2.25
38572	203		2
32886	203		2
32886	203		2
38008	203		2
36214	203		2
38455	203		1.97
39168	203		1.96

39418	203		1.96
39043	203		1.96
39400	203		1.96
39400	203		1.96
38533	203		1.96
38533	203		1.96
37387	203		1.96
38615	203		1.96
36979	203		1.96
36979	203		1.96
36979	203		1.96
36979	203		1.96
38246	203		1.96
38246	203		1.96
38246	203		1.96
37421	203		1.96
38898	203		1.96
38898	203		1.96
38898	203		1.96
39189	203		1.96
38410	203		1.82
37042	203		1.8
37662	203		1.76
37387	203		1.67
38400	203		1.59
38692	203		1.57
38087	203		1.3
37803	203		1.26
37373	203		1.2
38087	203		1.03
38087	203		1
35298	203		1
39186	203		0.98
39186	203		0.98
39186	203		0.98
38825	203		0.979
38825	203		0.979
37387	203		0.88
37421	203		0.54
38530	203		0.39
37373	203		0.38
37662	203		0.34
38615	203		0.34
37804	203		0.13

37387	202		5.82
38326	201		1.94
38565	201		1.9
38218	201		1.9
38541	201		1.9
36430	200		0.36
35510	194		1.3
38356	188		1.82
39536	188		1.82
39536	188		1.82
38420	188		1.82
38420	188		1.82
38356	188		1.82
39496	188		1.82
39496	188		1.82
39043	188		1.82
39489	188		1.82
39627	188		1.82
38454	188		1.8
38008	188		1.8
38648	188		1.8
38845	188		1.8
38565	188		1.8
35528	188		1.8
35528	188		1.8
38506	188		1.8
38506	188		1.8
31990	188		1.8
31990	188		1.8
38704	188		1.8
38704	188		1.8
39027	188		1.8
38218	188		1.8
38704	188		1.8
39193	188		1.8
38410	188		1.8
28730	180		24.1
257	180		19
332	173		22.5
24745	173		10.5
20122	154		6.5
334	150		20.1
29283	150	wrong units, no HP, but large Nox contribution	2.9

400	149		23
401	149		23
3377	149		22.93
36430	146		3.81
326	145		22
31728	145		1.75
31728	145		1.75
39285	145		1.4
38595	145		0.88
39322	145		0.7
39357	145		0.7
39195	145		0.7
39358	145		0.7
31610	143		1.2
24995	134		12.3
20495	134		12.3
327	129		14.6
26499	128		22.2
250	125		24
24809	110		4.7
24774	110		4.4
20328	110		2.1
28731	105		10.9
38117	105		2.54
328	100		11.69
31694	95		19.04
29796	95		18.99
25328	95		17.7
28884	95		15.9
26703	95		14.7
29892	95		13.7
315	95		13.6
24678	95		13.6
32173	95		1.8
28864	95		1.7
38845	92		2.5
38506	92		2.5
38506	92		2.5
38541	92		2.5
38339	92		2.5
38844	92		2.5
38844	92		2.5
39536	92		2.49
39168	92		2.49

38039	92		2.49
38039	92		2.49
39362	92		2.49
39532	92		0.89
39193	92		0.89
510	80		2.23
29271	80		2.2
29273	80		2.2
35298	75		2
33052	74		2.5
33052	74		2.5
33052	74		2.5
33052	74		2.5
33561	74		2.38
33561	74		2.38
28401	68		8.5
39320	63		2.02
329	59		5.9
20496	58		2.46
29172	50		2.6
29121	46		2.6
38165	46		2.6
33052	46		2.5
33052	46		2.5
36618	46		0.9
38372	46		0.07
38395	46		0.07
332	42		1.6
29121	40		1.5
38321	24.5		0.52
38239	24.5		0.52
38178	24.5		0.52
38238	24.5		0.52
38179	24.5		0.52
38186	24.5		0.52
38134	24.5		0.52
38132	24.5		0.52
38022	24.5		0.52
38028	24.5		0.52
38019	24.5		0.52
38133	24.5		0.52
38263	24.5		0.5
38261	24.5		0.5
38185	24.5		0.26

38185	24.5		0.26
443	13		0.6
21953	3.04	not HP (MMNTU/hr)	0.15
21953	3.04	not HP (MMNTU/hr)	0.15
39285	1	wrong units, no HP, but large Nox contribution	22.61
39290	1	wrong units, no HP, but large Nox contribution	0.57
39290	1	wrong units, no HP, but large Nox contribution	0.57
39290	1	wrong units, no HP, but large Nox contribution	0.57
377	0	no hp, high Nox	33.31
377	0	no hp, high Nox	33.31
32886	0	no hp, high Nox	25.88
38714	0	no hp, high Nox	24.96
258	0	wrong units, no HP, but large Nox contribution	24
34514	0	no hp, high Nox	22.9
30873	0	no hp, high Nox	22.86
25412	0	no hp, high Nox	21.5
224	0	wrong units, no HP, but large Nox contribution	19
348	0	no hp, high Nox	16.6
36953	0	no hp, high Nox	16.02
36953	0	no hp, high Nox	16.02
35341	0	no hp, high Nox	14.6
38756	0	no hp, high Nox	12.45
38756	0	no hp, high Nox	12.45
38756	0	no hp, high Nox	12.45
33301	0	no hp, high Nox	12.3
259	0	no hp, high Nox	12
259	0	no hp, high Nox	12
32886	0	no hp, high Nox	11.59
29063	0	no hp, high Nox	10.3
27245	0	no hp, high Nox	9.56
38509	0	no hp, high Nox	8.66
38509	0	no hp, high Nox	8.66
38509	0	no hp, high Nox	8.66
38509	0	no hp, high Nox	8.66
36189	0	no hp, high Nox	8.3
36189	0	no hp, high Nox	8.3
32886	0	no hp, high Nox	7.82
33078	0	no hp, high Nox	6
33418	0	no hp, high Nox	5.8

34772	0	no hp, high Nox	5.8
39029	0	no hp, high Nox	3.9
37475	0	no hp, high Nox	3.7
37475	0	no hp, high Nox	3.7
37475	0	no hp, high Nox	3.7
388	0	no hp, high Nox	3.68
30489	0	no hp, high Nox	3.4
38222	0	no hp, high Nox	3.23
32404	0	no hp, high Nox	3.2
34772	0	no hp, high Nox	3.2
38191	0	no hp, high Nox	2.59
34769	0	no hp, high Nox	2.1
35403	0	no hp, high Nox	2
35404	0	no hp, high Nox	2
38610	0	no hp, high Nox	1.96
34674	0	no hp, high Nox	0.7
38240	0	no hp, high Nox	0.52
38104	0	no hp, high Nox	0.52
38102	0	no hp, high Nox	0.52
38101	0	no hp, high Nox	0.52
38342	5000		24.1
38799	5000		14.5
38799	5000		14.5
38799	5000		14.5
38799	5000		14.5
38799	5000		14.5
38799	5000		14.5
38799	5000		14.5
38799	5000		14.5
38799	5000		14.5
32800	4735		22.9
32800	4735		22.9
32800	4735		22.9
32800	4735		22.9
32800	4735		22.9
32800	4735		22.9
32800	4735		22.9
32800	4735		22.9
669	3785		36.5
38827	3750		19.93
38827	3750		19.93
565	3550		24
565	3550		24
569	3550		17.1

VALOR EPC

569	3550		17.1
569	3550		17.1
569	3550		17.1
569	3550		17.1
569	3550		17.1
569	3550		17.1
569	3550		17.1
38904	3448		9.05
38904	3448		9.05
38904	3448		9.05
755	3200		46.4
755	3200		46.3
569	3200		39
569	3200		39
569	3200		39
569	3200		39
38505	2764		27.42
39171	2722		85.29
668	2650		42.2
601	2650		25
601	2650		25
32800	2520		11.4
32800	2520		11.4
571	2500		38.5
38617	2500		13.3
38617	2500		13.3
38617	2500		13.3
38617	2500		13.3
38827	2500		13.27
38827	2500		13.27
38049	2500		12.1
39153	2500		12.1
39153	2500		12.1
38342	2500		12.1
29590	2500		12.1
29590	2500		12.1
34824	2500		12.1
34824	2500		12.1
38720	2500		12.1
38196	2500		12.1
29403	2500		12.1
38910	2500		12.07
38910	2500		12.07
38359	2500		12.07

38359	2500		12.07
38359	2500		12.07
38359	2500		12.07
39498	2500		9.17
39553	2500		7.24
39553	2500		7.24
39553	2500		7.24
39553	2500		7.24
39553	2500		7.24
39553	2500		7.24
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39553	2500		7.24
38177	2500		7.24
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38177	2500		7.24
38177	2500		7.24
38177	2500		7.24
39575	2500		7.24
39575	2500		7.24
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39575	2500		7.24
39108	2500		7.24
36132	2500		7.24
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36132	2500		7.24
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36132	2500		7.24
36132	2500		7.24
39451	2500		7.24
39451	2500		7.24
37953	2500		7.2
37953	2500		7.2
37953	2500		7.2
37953	2500		7.2

37953	2500		7.2
37953	2500		7.2
37953	2500		7.2
37953	2500		7.2
36132	2500		7.18
36132	2500		7.18
38999	2500		7.18
38999	2500		7.18
38999	2500		7.18
39148	2500		7.18
39148	2500		7.18
39148	2500		7.18
39148	2500		7.18
39148	2500		7.18
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39148	2500		7.18
39148	2500		7.18
39451	2500		7.18
621	2370		16
36131	2370		13.7
36131	2370		13.7
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36131	2370		13.7
36131	2370		13.7
36131	2370		13.7
602	2370		11.2
602	2370		11.2
602	2370		11.2
602	2370		11.2
34645	2370		6.87
34645	2370		6.87
34645	2370		6.87
34645	2370		6.87
34645	2370		6.87
34645	2370		6.87
667	2300		154.5
667	2300		154.5
667	2300		154.5
668	2200		507
593	2200		28.4
609	2050		267.5
589	2000		566.1
569	2000		36.2
38342	1978		17.3

38342	1978		10.6
39498	1875		11.4
39498	1875		11.4
39498	1875		11.4
39498	1875		11.4
39498	1875		11.4
37713	1875		11.32
37766	1875		11.3
37766	1875		11.3
37713	1875		11.3
37713	1875		11.3
37713	1875		11.3
39153	1875		9.1
39153	1875		9.1
39153	1875		9.1
39153	1875		9.1
34027	1875		9.1
38049	1875		9.1
34824	1875		9.1
34027	1875		9.1
38049	1875		9.1
38196	1875		9.1
38196	1875		9.1
38196	1875		9.1
38196	1875		9.1
38196	1875		9.1
38049	1875		9.1
38694	1875		9.1
38694	1875		9.1
38694	1875		9.1
38694	1875		9.1
38694	1875		9.1
29590	1875		9.1
29590	1875		9.1
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29590	1875		9.1
34027	1875		9.1
37891	1875		9.1
37891	1875		9.1
38125	1875		9.1
38125	1875		9.1
29403	1875		9.1

29403	1875		9.1
38720	1875		9.1
39452	1875		9.1
38720	1875		9.1
38720	1875		9.1
39179	1875		9.05
39179	1875		9.05
39179	1875		9.05
39179	1875		9.05
39179	1875		9.05
39179	1875		9.05
38582	1875		9.05
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38582	1875		9.05
38582	1875		9.05
38582	1875		9.05
38904	1875		9.05
38904	1875		9.05
38904	1875		9.05
39006	1875		9.05
39006	1875		9.05
39006	1875		9.05
39006	1875		9.05
39006	1875		9.05
39006	1875		9.05
39517	1875		9.05
38489	1875		9.05
38489	1875		9.05
38489	1875		9.05
36802	1875		9.05
36802	1875		9.05
36802	1875		9.05
36802	1875		9.05
38401	1875		9.05
38401	1875		9.05
38401	1875		9.05
38401	1875		9.05
38401	1875		9.05
38401	1875		9.05
38401	1875		9.05
38401	1875		9.05
38401	1875		9.05
38999	1875		9.05

38999	1875		9.05
38999	1875		9.05
39267	1875		9.05
39267	1875		9.05
39267	1875		9.05
39267	1875		9.05
38479	1875		9.05
38479	1875		9.05
38479	1875		9.05
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38491	1875		9.05
38491	1875		9.05
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38491	1875		9.05
38552	1875		9.05
38552	1875		9.05
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38491	1875		9.05
38552	1875		9.05
38552	1875		9.05
38552	1875		9.05
38552	1875		9.05
39451	1875		5.43
39451	1875		5.43
39451	1875		5.43
38334	1875		5.4
38334	1875		5.4
38334	1875		5.4
38334	1875		5.4
38334	1875		5.4
38334	1875		5.4
37348	1863		9
37348	1863		9
37348	1863		9
612	1800		189.2
28228	1800	rpm not hp	19.1

753	1800	rpm not hp	16.2
21515	1800	rpm not hp	14.5
832	1800	rpm not hp	12.3
26161	1800	rpm not hp	12.3
37917	1800	rpm not hp	12
28925	1800	rpm not hp	6.8
28925	1800	rpm not hp	6.8
38097	1800	rpm not hp	6.6
33313	1800	rpm not hp	6.28
39481	1800	rpm not hp	5.61
39481	1800	rpm not hp	5.61
38462	1800	rpm not hp	5.6
38462	1800	rpm not hp	5.6
38029	1800	rpm not hp	3.9
38462	1800	rpm not hp	3.8
39222	1800	rpm not hp	3.8
31248	1800	rpm not hp	3.8
33093	1800	rpm not hp	3.71
38462	1800	rpm not hp	3.7
38462	1800	rpm not hp	3.7
39222	1800	rpm not hp	3.7
39642	1800	rpm not hp	3.14
39085	1800	rpm not hp	3.1
39085	1800	rpm not hp	3.1
38947	1800	rpm not hp	3.04
39452	1800	rpm not hp	2.9
39452	1800	rpm not hp	2.9
39452	1800	rpm not hp	2.9
31802	1800	rpm not hp	2.9
31802	1800	rpm not hp	2.9
39222	1800	rpm not hp	2.6
28957	1800	rpm not hp	2.6
38794	1800	rpm not hp	2
38794	1800	rpm not hp	2
36579	1800	rpm not hp	2
37507	1800	rpm not hp	2
39222	1800	rpm not hp	1.9
39090	1800	rpm not hp	1.9
39090	1800	rpm not hp	1.9
39090	1800	rpm not hp	1.9
39481	1800	rpm not hp	1.82
39481	1800	rpm not hp	1.82
39481	1800	rpm not hp	1.82
39222	1800	rpm not hp	1.8

35010	1800	rpm not hp	0.98
35010	1800	rpm not hp	0.98
35010	1800	rpm not hp	0.98
33901	1800	rpm not hp	0.98
33901	1800	rpm not hp	0.98
33901	1800	rpm not hp	0.98
34027	1775		8.6
34027	1775		8.6
34027	1775		8.6
34027	1775		8.6
38799	1775		8.6
37864	1775		8.6
37864	1775		8.6
37864	1775		8.6
37864	1775		8.6
29403	1775		8.6
35034	1775		8.6
38054	1775		8.6
38054	1775		8.6
37515	1775		8.57
37515	1775		8.57
37515	1775		8.57
37515	1775		8.57
35462	1755		12
38505	1747		9.42
38505	1747		9.42
34824	1725		8.33
29403	1725		8.3
39501	1680		27.98
818	1680		17.7
818	1680		17.7
34226	1680		16.2
38067	1680		8.32
38067	1680		8.32
38067	1680		8.32
38067	1680		8.32
38051	1680		7.1
660	1604		25.1
660	1604		8.1
609	1600		19.3
609	1600		19.3
609	1600		19.3
831	1600		14.5
33461	1500	x	2.6

33461	1500	x	2.6
33461	1500	x	1.9
32116	1480		18.6
36279	1480		14.3
36279	1480		14.3
36279	1480		14.3
36279	1480		14.3
38577	1480		12.84
38577	1480		12.84
38577	1480		12.84
38577	1480		12.84
38577	1480		12.84
38577	1480		12.84
38577	1480		12.84
763	1480		10.8
763	1480		10.4
763	1480		10.4
763	1480		10.4
763	1480		10.4
763	1480		10.4
26939	1478		28.5
657	1478		21.41
722	1478		19.3
722	1478		19.3
818	1478		15.6
31919	1478		12.49
31919	1478		12.49
31919	1478		12.49
832	1478		12.4
832	1478		12.4
592	1478		10.35
30350	1478		9.3
30350	1478		9.3
30350	1478		9.3
30350	1478		9.3
35592	1478		8.81
35592	1478		8.81
35592	1478		8.81
35592	1478		8.81
35592	1478		8.81
35592	1478		8.81
35592	1478		8.81
35592	1478		8.81
35592	1478		8.81

35592	1478		8.81
613	1478		8.4
613	1478		8.4
665	1478		4.6
665	1478		4.6
593	1478		3.7
33461	1400	rpm not hp	32.4
37926	1400	rpm not hp	25.9
598	1400	rpm not hp	25.9
37507	1400	rpm not hp	25.9
31248	1400		25.9
592	1400	rpm not hp	24.4
34752	1400	rpm not hp	24.4
753	1400		19.4
35338	1400		19.4
35338	1400		19.4
26440	1400		19.4
832	1400		19.4
26939	1400		19.4
26939	1400		19.4
642	1400		18.3
793	1400		18.3
570	1400		13.3
570	1400		13.3
570	1400		13.3
570	1400		13.3
35526	1400		13
33313	1400		12.94
37770	1400		12.7
37770	1400		12.7
37770	1400		12.6
37770	1400		12
33165	1400		9.99
39481	1400		8.33
39481	1400		8.33
37766	1400		8.1
37766	1400		8.1
37713	1400		8.1
35661	1400		6.7
37746	1400		6.7
37746	1400		6.7
37746	1400		6.7
37746	1400		6.7
37746	1400		6.7

37746	1400		6.7
37746	1400		6.7
37746	1400		6.7
29403	1400		6.7
39090	1400		6.7
37138	1400		6.7
37265	1400		6.7
37266	1400		6.7
37873	1400		6.7
37050	1400		6.7
38947	1400		6.67
32116	1400		6.66
32116	1400		6.66
32116	1400		6.66
38489	1400		6.66
38489	1400		6.66
38489	1400		6.66
38489	1400		6.66
38720	1400		6.66
38720	1400		6.66
29403	1400		6.5
37916	1400		3.9
37916	1400		3.9
37916	1400		3.9
39420	1400		3.33
37883	1400		3.3
26807	1380		26.7
602	1380		22.2
38067	1380		13.33
38067	1380		13.33
38067	1380		13.33
38067	1380		13.33
38067	1380		13.33
38067	1380		13.33
38067	1380		13.3
38082	1380		13.3
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38082	1380		13.3
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755	1380		13.3
33175	1380		13.3
565	1380		13.3
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38083	1380		13.3
38083	1380		13.3
755	1380		13.3
38905	1380		8.33
38905	1380		8.33
38905	1380		8.33
38905	1380		8.33
38905	1380		8.33
38905	1380		8.33
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38905	1380		8.33
38905	1380		8.33
34227	1380		8.33
37362	1380		8.32
38981	1380		8.32
38981	1380		8.32
38981	1380		8.32
38981	1380		8.32
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35139	1380		8.32
35139	1380		8.32
35139	1380		8.32
35139	1380		8.32
35139	1380		8.32
35139	1380		8.32
38928	1380		8.32

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38928	1380		8.32
38928	1380		8.32
38447	1380		8.32
38473	1380		7.33
38473	1380		7.33
38049	1380		6.7
37891	1380		6.7
37891	1380		6.7
37891	1380		6.7
37891	1380		6.7
38342	1380		6.7
38342	1380		6.7
29590	1380		6.7
29590	1380		6.7
38049	1380		6.7
38049	1380		6.7
37771	1380		6.7
37771	1380		6.7
37771	1380		6.7
37771	1380		6.7
37891	1380		6.7
37891	1380		6.7
38125	1380		6.7
38125	1380		6.7
38125	1380		6.7
38125	1380		6.7
38799	1380		6.7
38799	1380		6.7
29403	1380		6.7
29403	1380		6.7
29403	1380		6.7
29403	1380		6.7
29403	1380		6.7
29403	1380		6.7
34824	1380		6.7
38334	1380		6.7
37605	1380		6.7
35048	1380		6.7
35048	1380		6.7
35048	1380		6.7
35048	1380		6.7
35048	1380		6.7
35048	1380		6.7

763	1380		6.7
35048	1380		6.7
35048	1380		6.7
34824	1380		6.7
39433	1380		6.66
38463	1380		6.66
38314	1380		6.66
31247	1380		6.66
38463	1380		6.66
38910	1380		6.66
38910	1380		6.66
38910	1380		6.66
38910	1380		6.66
38910	1380		6.66
39108	1380		6.66
39108	1380		6.66
39108	1380		6.66
39108	1380		6.66
39108	1380		6.66
39108	1380		6.66
38679	1380		6.66
39550	1380		6.66
38082	1380		3.11
38189	1380		3.11
38051	1380		2.47
612	1350		142.8
612	1350		142.8
612	1350		142.8
612	1350		142.8
612	1350		142.8
612	1350		142.8
612	1350		125.6
763	1340		25.9
630	1340		25.88
34583	1340		25.88
33987	1340		25.88
755	1340		19.4
755	1340		19.4
31248	1340		19.4
753	1340		19.4
27079	1340		19.4
27079	1340		19.4
38093	1340		12.9
34824	1340		6.5

34824	1340		6.5
34824	1340		6.5
34824	1340		6.5
630	1289		16.43
657	1232		29.74
26045	1232		23.8
664	1232		17.9
664	1232		17.9
24671	1232		11.9
24671	1232		11.9
24671	1232		11.9
817	1232		11.9
817	1232		11.9
609	1200		234.8
609	1200		234.8
609	1200		234.8
609	1200		234.8
609	1200		234.8
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609	1200		234.8
609	1200		23.2
609	1200		23.2
609	1200		23.2
609	1200		23.2
609	1200		23.2
609	1200		23.2
609	1200		23.2
4664	1200		22.2
598	1200		21.02
744	1200		21
34167	1200		16.03
34167	1200		16.03
609	1200		13.4
12454	1200		6
612	1195		125.6
629	1195		23.1
4664	1151		22.2
31863	1150		22.21
571	1100		125
571	1100		125
571	1100		125
569	1100		122
569	1100		122

610	1100		72.7
569	1100		21.2
569	1100		21.2
740	1100		21.2
740	1100		21.2
569	1100		21.2
621	1100		21.2
30535	1100		21.2
30535	1100		21.2
24552	1100		21.2
609	1100		20.4
571	1100		17.1
571	1100		17.1
658	1097		21.2
658	1097		21.2
595	1085		21
595	1085		21
595	1085		21
39501	1080		34.65
629	1073		51.79
565	1035		5
605	1000		33.8
26045	1000		17.3
26440	1000		8.6
26440	1000		8.6
26440	1000		8.6
38371	945		22.81
725	900		15.5
725	900		15.4
794	900		11.61
665	900		1.3
665	900		1.3
665	900		0.97
665	900		0.97
665	900		0.97
665	900		0.97
24552	896		16.5
568	896		8.7
568	896		8.7
610	880		183.5
613	860		16.6
38070	839		39.8
38438	836		4.03
38183	836		4.03

38439	836		4
38863	836		4
38838	836		1.26
697	830		16
698	830		16
621	818		15.8
731	814		7.7
641	805		19.3
641	805		19.3
641	805		19.3
610	800		121.8
610	800		121.8
610	800		121.8
669	800		36.5
595	800		23.2
595	800		23.2
595	800		23.2
595	800		23.2
649	800		15.44
793	800		15.4
755	800		14.5
612	780		149.8
612	780		149.8
612	780		149.8
612	780		15.1
38162	755		9.95
38162	755		9.95
38162	755		9.95
641	750		19.3
641	750		19.3
38067	690		6.7
38939	690		6.66
38150	690		6.66
38789	690		6.66
38963	690		6.66
39523	690		6.66
39543	690		6.66
37912	690		4.16
39436	690		3.33
38665	690		3.33
38740	690		3.33
26069	690		3.3
39309	684		6.6
39360	684		6.6

36088	671		9.7
39117	670		12.94
39048	670		3.2
39048	670		3.2
38433	668		42
34824	650		2.79
34824	650		2.79
38083	644		3.1
832	637		12.3
831	637		12.3
831	637		12.3
26161	637		12.3
638	636		11.1
638	636		11.1
39523	636		6.14
39543	636		6.14
38941	630		12.2
734	625		12
37515	612		3.94
37515	612		3.94
610	600		109.9
610	600		109.9
610	600		109.9
37593	600		41.71
698	600		14.5
38810	600		5.79
39516	600		2.9
39516	600		2.9
39516	600		2.9
39517	600		2.9
39517	600		2.9
39517	600		2.9
631	594		64.4
655	585		61.29
39550	581		5.64
39520	581		5.61
38740	581		5.6
38740	581		5.6
31863	581		2.81
31863	581		2.81
31863	581		2.81
38469	581		1.94
29959	563		16.2
39528	550		5.31

39528	550		5.31
39528	550		5.31
39073	550		5.3
39073	550		5.3
35059	550		5.3
39163	550		5.3
34697	550		5.3
34697	550		5.3
37593	540		6.78
701	500		9.69
565	495		9.6
565	495		9.6
29195	448		12.9
38075	440		7.4
29139	440		7.4
20510	440		7.2
810	440		6.96
37544	440		3.71
38075	440		3.7
38108	440		3.7
38439	437		1.3
38863	437		1.3
38438	437		1.26
38838	437		1.26
38183	437		1.26
34175	415		8.01
38162	402		0.13
24786	400		21.9
27656	400		21
799	400		11
809	400		10.5
24746	400	rpm not hp	10.5
20510	400		10.2
38334	400		7.7
29139	400		6.7
27656	400		6.5
38810	400		5.18
38810	400		5.18
38228	400		3.9
38228	400		3.9
38021	400		3.9
38021	400		3.9
38897	400		3.9
39072	400		3.86

38195	400		3.86
38212	400		3.86
38952	400		3.86
39360	400		3.86
39309	400		3.86
38949	400		2.41
38948	400		2.41
39081	400		1.93
39081	400		1.93
39081	400		1.93
39089	400		1.93
39089	400		1.93
39089	400		1.93
39093	400		1.93
39093	400		1.93
39093	400		1.93
39308	400		1.93
39308	400		1.93
39308	400		1.93
39254	400		1.93
39254	400		1.93
39254	400		1.93
38949	400		0.89
38794	390		3.8
38794	390		3.8
38740	390		3.8
39117	390		3.77
39550	390		3.77
38789	390		3.77
39427	389		5.6
33138	384		4.63
34220	382		3.669
38120	380		11.74
38864	380		3.67
38864	380		3.67
38864	380		3.67
38227	380		2.29
37362	380		2.29
38439	375		1.7
38407	364		3.51
38407	364		3.51
38407	364		3.51
39163	362		3.5
38914	362		0.31

38914	362		0.31
38914	362		0.31
38914	362		0.31
38934	362		0.31
38934	362		0.31
38934	362		0.31
38934	362		0.31
38934	362		0.31
28018	360		11.4
819	360		9.75
813	360		9.75
24975	360		8.8
24974	360		4.9
28803	346		6.7
28803	346		6.7
27184	346		6.67
38827	335		3.24
38827	335		3.24
38617	335		3.2
38617	335		3.2
38889	332		3.21
673	325		12.5
38015	325		3.1
595	321		17.1
595	321		17.1
39437	315		3.04
38473	304		2.94
38473	304		2.94
37605	302		2.9
639	300		31.86
713	300		9.84
670	300		7.88
730	295		10.39
730	295		10.39
12418	288		8.34
747	280		24.79
38954	276		1.67
38905	276		1.67
38404	272		2.6
38404	272		2.6
38404	272		2.6
38404	272		2.6
38404	272		2.6
38404	272		2.6

38042	272		0.6
28803	269		5.2
28803	269		5.2
38889	268		2.6
38889	268		2.6
38789	268		2.6
38963	268		2.6
38789	268		2.6
38963	268		2.6
38794	268		2.59
38794	268		2.59
39117	268		2.59
39117	268		2.59
32796	266		22.9
38054	236		0.5
38054	236		0.5
33165	231		4.5
721	230		6.84
756	221		6.09
38042	214		1.9
38799	203		3.9
39502	203		2.45
38404	203		2
38404	203		2
38897	203		2
27474	203		2
38896	203		1.96
38896	203		1.96
38896	203		1.96
38469	203		1.96
38889	203		1.96
35953	203		0.98
35953	203		0.98
35953	203		0.98
35953	203		0.98
35953	203		0.98
35953	203		0.98
38447	203		0.979
38447	203		0.979
38447	203		0.979
38948	201		1.94
39520	201		1.94
38949	201		1.94
568	200		14.5

38359	199		1.92
37543	192		3.71
37593	192		3.71
39117	188		1.82
39520	188		1.82
38665	188		1.82
38963	188		1.82
38789	188		1.82
38794	188		1.8
38015	188		1.8
38015	188		1.8
38015	188		1.8
38794	188		1.8
38740	188		1.8
38889	188		1.8
38860	188		1.8
38860	188		1.8
38860	188		1.8
39073	188		1.8
39073	188		1.8
39163	188		1.8
39163	188		1.8
38624	188		1.8
38624	188		1.8
38624	188		1.8
39427	173		6.23
38950	173		4.2
39427	173		4.18
4609	173		3.3
39500	170		1.8
38909	152		4.4
38909	152		4.4
38909	152		4.4
678	150		21.87
701	145		23
674	145		17.12
37222	145		1.4
37223	145		1.4
34697	145		1.4
37362	145		0.87
35483	145		0.87
38195	134		1.29
38212	134		1.29
38227	134		1.29

39437	134		1.29
39502	134		1.23
38371	134		0.06
38162	134		0.04
707	127		24.5
602	125		0.97
693	118		18.25
25488	110		4.7
2424	95		14.5
24672	95		13.7
38021	92		2.5
38021	92		2.49
39449	92		2.49
38906	92		2.49
38948	92		1.11
38195	92		0.89
38212	92		0.89
38227	92		0.89
38954	92		0.89
39550	92		0.89
30105	89.1		9.2
667	75		0.2
38617	72		2
38473	72		1.97
38827	72		1.97
32800	70		0.1
20494	64		7.35
39267	63		2.02
38694	63		0.2
38694	63		0.2
36290	60		0.4
667	60		0.3
667	50		0.1
38371	46		2.6
33003	46		1.7
702	45		5.69
30906	28		1.35
39201	28		1.35
39348	25		1.2
30907	25		1.2
39319	25		1.2
38792	25		1.2
38131	24.5		0.52
38236	24.5		0.52

38241	24.5		0.52
38322	24.5		0.52
38184	24.5		0.52
38030	24.5		0.52
38023	24.5		0.52
38023	24.5		0.52
38260	24.5		0.5
38264	24.5		0.5
38262	24.5		0.3
38262	24.5		0.3
667	22.5		0.1
30906	19		0.92
24746	1.5	not HP (MMNTU/hr)	0.5
38567	0	no hp, high Nox	12.45
38567	0	no hp, high Nox	12.45
38567	0	no hp, high Nox	12.45
31895	0	no hp, high Nox	12
31895	0	no hp, high Nox	12
38633	0	no hp, high Nox	11.59
37521	0	no hp, high Nox	6.7
33987	0	no hp, high Nox	6.7
34699	0	no hp, high Nox	5.8
38091	0	no hp, high Nox	3.9
38091	0	no hp, high Nox	3.9
33093	0	no hp, high Nox	3.88
32906	0	no hp, high Nox	3.7
33008	0	no hp, high Nox	3.5
26440	0	no hp, high Nox	3.33
34585	0	no hp, high Nox	3.2
34585	0	no hp, high Nox	2.9
37906	0	no hp, high Nox	2.7
33008	0	no hp, high Nox	2.2
33008	0	no hp, high Nox	2.2
38226	0	no hp, high Nox	2
34585	0	no hp, high Nox	2
34571	0	no hp, high Nox	1
34571	0	no hp, high Nox	1
34954	0	no hp, high Nox	1
34954	0	no hp, high Nox	1
34956	0	no hp, high Nox	1
38318	0	no hp, high Nox	0.52
38316	0	no hp, high Nox	0.52
38317	0	no hp, high Nox	0.26
38317	0	no hp, high Nox	0.26

38120		no hp, high Nox	11.74
38120		no hp, high Nox	11.7
26151	2200		18.1
2130	2200		8.75
28006	2000		5.7
2221	1800	rpm not hp	81
2221	1800	rpm not hp	81
2221	1800	rpm not hp	81
27074	1800	rpm not hp	31.9
24796	1800	rpm not hp	22.5
3452	1800	rpm not hp	22.4
28236	1800	rpm not hp	18.3
27018	1800	rpm not hp	18.3
24735	1800	rpm not hp	18.2
29904	1800	rpm not hp	17.6
29907	1800	rpm not hp	17.6
25046	1800	rpm not hp	15.9
25046	1800	rpm not hp	15.9
25046	1800	rpm not hp	15.9
25046	1800	rpm not hp	15.9
25046	1800	rpm not hp	15.9
25046	1800	rpm not hp	15.9
23884	1800	rpm not hp	15.3
23884	1800	rpm not hp	15.3
26321	1800	rpm not hp	15.3
24186	1800	rpm not hp	15.2
21759	1800	rpm not hp	14.5
21763	1800	rpm not hp	14.5
24190	1800	rpm not hp	14.5
25896	1800	rpm not hp	14.5
25896	1800	rpm not hp	14.5
25896	1800	rpm not hp	14.5
25896	1800	rpm not hp	14.5
25896	1800	rpm not hp	14.5
25896	1800	rpm not hp	14.5
25896	1800	rpm not hp	14.5
25896	1800	rpm not hp	14.5
25896	1800	rpm not hp	14.5
25896	1800	rpm not hp	14.5
24592	1800	rpm not hp	14.5
22254	1800	rpm not hp	14.5
24593	1800	rpm not hp	14.5
26134	1800	rpm not hp	14
28156	1800	rpm not hp	13.2

28156	1800	rpm not hp	13.2
28156	1800	rpm not hp	13.2
28156	1800	rpm not hp	13.2
28156	1800	rpm not hp	13.2
28156	1800	rpm not hp	13.2
28156	1800	rpm not hp	13.2
24800	1800	rpm not hp	13.2
24798	1800	rpm not hp	12.7
25157	1800	rpm not hp	12.4
12421	1800	rpm not hp	12.3
12421	1800	rpm not hp	12.3
2227	1800	rpm not hp	12.3
28024	1800	rpm not hp	12.3
3596	1800	rpm not hp	12.05
21951	1800	rpm not hp	12
28023	1800	rpm not hp	10.7
3451	1800	rpm not hp	10.5
3451	1800	rpm not hp	10.5
3451	1800	rpm not hp	10.5
3451	1800	rpm not hp	10.5
3451	1800	rpm not hp	10.5
3451	1800	rpm not hp	10.5
3451	1800	rpm not hp	10.5
3451	1800	rpm not hp	10.5
3451	1800	rpm not hp	10.5
3451	1800	rpm not hp	10.5
3451	1800	rpm not hp	10.5
3451	1800	rpm not hp	10.5
3451	1800	rpm not hp	10.5
3451	1800	rpm not hp	10.5
3451	1800	rpm not hp	10.5
28005	1800	rpm not hp	9.3
24797	1800	rpm not hp	9.2
2009	1800	rpm not hp	8.5
24856	1800	rpm not hp	8.2
27966	1800	rpm not hp	8.1
27059	1800	rpm not hp	8.1
28024	1800	rpm not hp	8.1
27009	1800	rpm not hp	8
27011	1800	rpm not hp	8
27011	1800	rpm not hp	8
27012	1800	rpm not hp	8
27018	1800	rpm not hp	8
2009	1800	rpm not hp	7.11

2009	1800	rpm not hp	7.11
2009	1800	rpm not hp	7.11
27024	1800	rpm not hp	6.8
20064	1800	rpm not hp	6.7
25079	1800	rpm not hp	5.5
27018	1800	rpm not hp	5.4
27074	1800	rpm not hp	5.4
1884	1800	rpm not hp	4.04
2078	1800	rpm not hp	3.6
2078	1800	rpm not hp	3.6
2078	1800	rpm not hp	3.6
2078	1800	rpm not hp	3.6
2078	1800	rpm not hp	3.6
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2078	1800	rpm not hp	3.6
2078	1800	rpm not hp	3.6
2078	1800	rpm not hp	3.6
2078	1800	rpm not hp	3.6
28023	1800	rpm not hp	3.4
29948	1800	rpm not hp	2.9
29948	1800	rpm not hp	2.9
29948	1800	rpm not hp	2.9
29948	1800	rpm not hp	2.9
29948	1800	rpm not hp	2.9
29948	1800	rpm not hp	2.9
29948	1800	rpm not hp	2.9
29948	1800	rpm not hp	2.9
29948	1800	rpm not hp	2.9
34301	1800	rpm not hp	0.98
28023	1800	rpm not hp	0.9
28006	1600		4.5
28023	1600		4.5
27132	1500		24.4
27012	1500		7.7
27009	1500		6.1
2032	1478		21.4
2145	1400		24.39
28249	1400		19.5
24187	1400		19.4
24188	1400		14.5
24474	1400		13.8
24474	1400		13.8

24474	1400		13.8
24474	1400		13.8
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24474	1400		13.8
24474	1400		13.8
22393	1400		12.15
27133	1340		20.7
27133	1340		20.7
27133	1340		20.7
27133	1340		20.7
27133	1340		20.7
28285	1200		4.6
28285	1200		4.6
28285	1200		4.6
28285	1200		4.6
28285	1200		4.6
2106	1178		17.1
2136	1150		32
1883	1085		21
2188	1085		20.95
2307	1085		19.7
2027	1072		15.52
2166	950		18.29
2135	825		23.89
2153	810		23.5
25046	750		1.84
24579	750		1.8
2079	738		10.69
1954	738		10.39
27074	700		0.61
27074	700		0.61
27011	700		0.6
27011	700		0.6
27012	700		0.6
27012	700		0.6
27018	700		0.6
27018	700		0.6
24185	633		13.7
2095	621		19.2

1983	615		8.3
4586	600	wrong units, no HP, but large Nox contribution	11.59
4586	600	wrong units, no HP, but large Nox contribution	11.59
4586	600	wrong units, no HP, but large Nox contribution	11.59
4586	600	wrong units, no HP, but large Nox contribution	11.59
4586	600	wrong units, no HP, but large Nox contribution	11.59
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4586	600	wrong units, no HP, but large Nox contribution	11.59
4586	600	wrong units, no HP, but large Nox contribution	11.59

4586	600	wrong units, no HP, but large Nox contribution	11.59
4586	600	wrong units, no HP, but large Nox contribution	11.59
4586	600	wrong units, no HP, but large Nox contribution	11.59
28912	600		10.9
27966	600		2.3
27311	600		2.3
27059	600		0.5
25157	600		0.5
2224	580		11.19
2224	580		11.19
2224	580		11.19
2224	580		11.19
2308	540		10.42
2226	540		10.39
26006	530		16.2
26887	530		10.7
2080	500		24.1
2193	500		12.74
2193	500		12.74
2193	500		12.74
2193	500		12.74
2193	500		12.74
2193	500		12.74
2193	500		12.74
2193	500		12.74
2193	500		12.74
2245	500		4.82
27063	475		2.3
3416	440		12.6
4658	440		12.6
24191	440		6.7
3452	420	wrong units, no HP, but large Nox contribution	22.4
34301	400		23.6
27129	400		21
2011	400		16.7
22345	400		16.69
34301	400		13.6
27128	400		13.6
27130	400		11.4
27130	400		11.4

27130	400		11.4
27130	400		11.4
27130	400		11.4
21641	400		11.05
21641	400		11.05
4587	400		10.5
34301	400		10.5
26897	400		8.1
34301	400		6.5
1908	369		17.79
2201	365		37.7
2217	365		37.7
2042	360		17.39
34301	360		11.4
1864	360		9.4
34301	360		9.4
24579	360		5.1
24579	360		5.1
24579	360		5.1
24579	360		5.1
24579	360		5.1
24579	360		5.1
24579	360		5.1
34301	360		4.7
1807	360		4.03
2187	346		16.7
25493	346		7.4
25493	346		7.4
2098	346		6.69
2197	325		36.4
2061	300		17.39
29915	281		22.5
23620	281		5.4
23620	281		5.4
23620	281		5.4
23620	281		5.4
23620	281		5.4
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23620	281		5.4
23620	281		5.4
23620	281		5.4
23620	281		5.4
23620	281		5.4
27158	280		19.4

1886	280		12.18
1852	265		25.1
2055	251		35.09
1936	233		29
28645	225		17.1
1337	220		40
2270	220		26.6
20315	215		32.4
31953	215		1
32632	203		35.7
33569	203		3.9
27024	203		3.9
2111	200		37.7
2269	200		19.89
1977	194		39.7
1879	194		37.65
1879	194		37.65
1879	194		37.65
1879	194		37.65
1879	194		37.65
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1879	194		37.65
1879	194		37.65
1879	194		37.65
1879	194		37.65
1879	194		37.65
37847	190		30.1
1935	188		20.29
26750	188		19.2
28772	188		19.2
25310	175		24.5
25310	175		24.5
25310	175		24.5
25310	175		24.5
1897	175		16.89
1897	175		16.89
28009	175		10.47
27158	175		2.3
28008	163		7.44

28459	163		7.4
1926	154		19.6
36343	152		17.8
2338	150		23.89
26316	150		23.7
2335	150		21.87
1904	150		20.6
28309	150		0.4
28310	150		0.4
2203	149		23
2325	149		21.6
2058	145		36.29
27032	145		30.2
22060	145		29.3
22060	145		29.3
22060	145		29.3
22060	145		29.3
22060	145		29.3
22060	145		29.3
2241	145		22.36
37842	145		22.3
37842	145		22.3
29901	145		22.3
29903	145		22.3
28876	145		15.3
28876	145		15.3
28876	145		15.3
2258	140		21.6
2258	140		21.6
2258	140		21.6
2258	140		21.6
2258	140		21.6
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2258	140		21.6
2258	140		21.6
1750	130		18
2066	129		23.2

2132	129		23.2
2248	128		16.9
2248	128		16.89
2248	128		16.89
2248	128		16.89
2248	128		16.89
2248	128		16.89
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2248	128		16.89
2248	128		16.89
2248	128		16.89
2248	128		16.89
2248	128		16.89
2105	126		8.89
27984	125		20.57
3442	125	wrong units, no HP, but large Nox contribution	19.4
2312	125		15.3

2312	125		15.3
26839	125		13.7
2330	120		16.79
2322	118		15.84
1933	118		15.6
28156	118		13.2
28156	118		13.2
28156	118		13.2
28156	118		13.2
28156	118		13.2
28156	118		13.2
20356	118		12.43
20356	118		12.43
20356	118		12.43
20356	118		12.43
20356	118		12.43
20356	118		12.43
20356	118		12.43
20356	118		12.43
20356	118		12.43
20356	118		12.43
2293	108		16.67
20315	108		3.9
20315	108		3.9
20315	108		3.9
20315	108		3.9
20315	108		3.9
20315	108		3.9
20315	108		3.9
20315	108		3.9
20315	108		3.9
20315	108		3.9
28025	99		2.7
28025	99		2.7
28025	99		2.7
28645	99		1.7
28459	99		1.7
37842	98		7.1
37842	98		7.1
27311	95		18.1
29905	95		16.7
1848	95		14.5
1916	95		14.5
1931	95		14.5

28360	95		14.48
2195	95		14.43
2242	95		14.4
1816	95		13.58
1816	95		13.58
1816	95		13.57
1906	95		12.8
1960	95		12.8
1960	95		12.8
1960	95		12.8
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1960	95		12.8
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1903	95		12.8
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1903	95		12.8
1903	95		12.8
1903	95		12.8
1964	95		12.8
2167	95		10.3
29889	95		9.9
26792	95		9.3
26316	90		18.3
26792	89.1		1.2
26887	89.1		1.2
26887	89.1		1.2
26897	89.1		1.2
26897	89.1		1.2
1826	84		11.22
24898	84		10.2
27051	84		8.7
1877	82		11.69
1877	82		11.69
1877	82		11.69
1877	82		11.69
1877	82		11.69
1877	82		11.69
1877	82		11.69
29049	80		9.9
2012	80		8.8
2260	80		8.75
28023	74		1.3
28009	74		1.25
2323	68		7.34
2214	68		7.3
20004	68		7.3
27009	68		0.6
27009	68		0.6
2013	64		6.9
1870	64		6.09
1871	64		6.09

1902	64		6.09
4608	63		8
26887	60.8		9.3
26897	60.8		9.3
28459	60.8		9.3
28008	60.8		9.26
2215	58		6.3
27018	55		5.3
28005	55		0.9
2261	50		5.8
2261	50		5.8
2261	50		5.8
2261	50		5.8
2261	50		5.8
28005	50		5.1
28005	50		5.1
28025	50		5.1
28008	50		0.84
28009	50		0.84
1895	46		4.8
20003	45		4.9
2229	45		4.86
28008	45		4.51
27032	45		4.3
1896	38		4
1896	38		4
1896	38		4
1896	38		4
1896	38		4
1896	38		4
24856	25		2.3
26134	25		2.3
24579	25		1.8
29049	25		1.4
20315	21.4		2.3
32632	21.4		2.3
27024	20		2.2
27024	20		2.2
24800	20		1.8
24796	20		1.8
24797	20		1.8
24798	20		1.8
24799	20		1.8
24856	20		1.8

26134	20		1.8
25079	20		1.8
29049	20		1.8
24898	20		1.8
24735	20		1.8
26151	20		1.8
28912	20		0.53
27051	20		0.5
27032	20		0.4
27032	20		0.4
2193	18		0.6
2193	18		0.6
2002	16		21.89
1999	16		21.89
28360	16		0.44
26966	0	no hp, high Nox	24
27127	0	no hp, high Nox	22.75
20318	0	no hp, high Nox	20.1
27143	0	no hp, high Nox	18.32
36101	0	no hp, high Nox	16.73
36101	0	no hp, high Nox	16.73
36119	0	no hp, high Nox	16.73
21948	0	no hp, high Nox	14.5
27131	0	no hp, high Nox	14.4
27134	0	no hp, high Nox	12.22
1987	0	no hp, high Nox	11.86
36119	0	no hp, high Nox	8.5
1986	0	no hp, high Nox	8.39
27032	0	no hp, high Nox	4.8
27143	0	no hp, high Nox	4.57
27275	0	no hp, high Nox	3.7
36119	0	no hp, high Nox	2.61
36119	0	no hp, high Nox	2.61
25493	0	no hp, high Nox	2.3
27275	0	no hp, high Nox	1.8
27275	0	no hp, high Nox	1.4
27143	0	no hp, high Nox	0.61
26966	0	no hp, high Nox	0.51
1053	3335		25.9
1053	3335		25.9
971	3335		22.5
971	3335		22.5
1038	2650		38.4
1038	2650		38.4

1038	2650		38.4
1038	2650		38.4
989	2650		36.1
989	2650		36.1
989	2650		36.1
1012	2650		35.8
25878	2370		14.4
25878	2129		14.4
25878	2129		14.4
25878	2129		14.4
1021	2000		5.7
24978	1800	rpm not hp	24.1
3413	1800	rpm not hp	23.5
24206	1800	rpm not hp	15
24206	1800	rpm not hp	15
3413	1800	rpm not hp	1.7
3413	1800	rpm not hp	1.7
35174	1775		7.8
35174	1775		7.8
1018	1508		8
1040	1480		20
34542	1480		19.5
34542	1480		19.5
34542	1480		19.5
34542	1480		19.5
34542	1480		19.5
1002	1480		15.6
3476	1480		6.9
1034	1478		19.9
1034	1478		19.9
1009	1478		19.9
1009	1478		19.9
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1009	1478		19.9
1009	1478		19.9
1009	1478		19.9
1009	1478		19.9
1007	1478		19.8
1007	1478		19.8
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1007	1478		19.8
1007	1478		19.8
1007	1478		19.8
1007	1478		19.8
3523	1478		19.7
3476	1478		19.2
1011	1478		12
1011	1478		12
1020	1478		12
1011	1478		12
1011	1478		12
1011	1478		12
1011	1478		12
1020	1478		12
1011	1478		12
1020	1478		12
1011	1478		12
1011	1478		12
1011	1478		12
1018	1478		11.98
1018	1478		11.98
1057	1478		11.9
1057	1478		11.9
1057	1478		11.9
998	1478		11.9
1006	1478		11.9
998	1478		11.9
1006	1478		11.9
1006	1478		11.9
1006	1478		11.9
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1006	1478		11.9
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1006	1478		11.9
998	1478		11.9
998	1478		11.9
3517	1400	rpm not hp	28.9
25061	1400		18
25061	1400		18
1027	1400		17.9
1027	1400		17.9
1027	1400		17.9
23704	1400		17.6
23704	1400		17.6
23704	1400		17.6
23704	1400		17.6
23827	1400		17.6
23827	1400		17.6
23827	1400		17.6
23827	1400		17.6
23827	1400		17.6
3521	1400		17.2
3521	1400		17.2
3523	1400		16.8
35174	1400		12.2
35174	1400		12.2
35174	1400		12.2
35174	1400		6.1
35174	1400		6.1
37568	1380		13.33
38697	1380		12.31
38979	1380		12.25
1039	1355		19.6
1039	1355		19.6
1012	1350		18.2
3476	1322		19.2
1030	1265		24.44
21709	1265		22.3
21709	1265		22.3
21709	1265		22.3
2386	1265		18.3
1020	1265		17.6
1011	1265		17.6
1011	1265		17.6
1040	1233		16.6

1040	1233		16.6
1013	1232		16.6
1013	1232		16.6
1013	1232		16.6
1013	1232		16.6
1013	1232		16.6
1013	1232		16.6
1013	1232		16.6
1013	1232		16.6
1002	1232		16.5
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1037	1232		16.4
1057	1215		16.3
23704	1200		21
23704	1200	x	1.3
23827	1200		1.3
24516	1190		17.3
1005	1150		21.31
24516	1085		20.9
1002	1025		9.3
985	1000	x	8.5
25878	975		21.76

21709	861		15.2
1002	754		8.5
37568	690		3.33
38697	690		3.08
38979	690		3.06
20128	637		12.3
28461	637		12.3
1002	607		2.72
993	600		9.6
38697	600		5.35
38697	600		5.35
38697	600		5.35
38979	600		5.33
38979	600		5.33
38979	600		5.33
1030	567		11
1010	515		3.2
38697	400		3.57
38979	400		3.55
37568	400		2.39
37568	400		2.39
37568	400		2.39
992	335		13
1031	335		12.89
1024	310		9.23
20128	286		22.52
1064	286		19.5
999	282		39
999	282		39
985	272		4.9
997	240		19.5
1070	226		37.06
1075	221		8.8
37568	203		0.98
1023	200		23.7
25878	198		3.8
25878	198		3.8
971	196		12.1
971	196		12.1
1017	185		23.7
1004	178		29.89
1004	178		29.89
24120	175		9.5
24120	175		9.5

28461	175		3.4
1068	173		8.35
1068	173		3.34
1019	164		15.6
1016	150		17.29
1015	150		17.1
32999	145		6.6
1036	125		17.79
37568	118		0.57
38697	118		0.48
38979	118		0.48
32999	110		2.1
21709	96		0.15
1011	84		1.3
1011	84		1.3
1020	84		1.3
999	70		7.5
999	70		7.5
1008	57		7.2
1057	57		0.9
1024	40		3.58
1024	40		3.58
1070	25		1.1
1008	21.4		2.1
988	0	wrong units, no HP, but large Nox contribution	44
27156	0	no hp, high Nox	19.72
34037	0	no hp, high Nox	10.5
32988	0	no hp, high Nox	1.9
32988	0	no hp, high Nox	1.5
32988	0	no hp, high Nox	0.95
25854	23700	hp order of magnitude incorrect	16
25854	23700	hp order of magnitude incorrect	16
1148	4445		28.2
1148	4445		28.2
28775	3600	x	1.4
1148	3550		22.5
1148	3400		218
1148	3400		218
1148	3400		218
1145	3335		25.9
1154	3335		25.9
1319	3335		25.9
1146	3335		24

1146	3335		24
1153	3335		22.9
1154	3162		25.9
23839	2800		16.1
1181	2650		38.4
1181	2650		38.4
1331	2650		38.4
1315	2650		38.4
1331	2650		38.4
1331	2650		38.4
1193	2650		38.4
1183	2650		38.4
1183	2650		38.4
1183	2650		38.4
1183	2650		38.4
1193	2650		38.4
1315	2650		36.3
36504	2650		35.7
36504	2650		35.7
20136	2302		19.5
1148	2222		20.2
1148	2222		20.2
1148	2222		20.2
27948	2200	x	15.5
23726	2200		8.38
23725	2200		5.54
28055	2000	rpm not hp	5.2
27910	2000	rpm not hp	5.1
27948	2000	rpm not hp	5.1
27548	2000	rpm not hp	5
27563	2000	rpm not hp	2.2
1223	1800	rpm not hp	28.1
28775	1800	rpm not hp	25.6
38750	1800	rpm not hp	23.9
1233	1800	rpm not hp	23.8
12448	1800	rpm not hp	23.8
12448	1800	rpm not hp	23.8
12448	1800	rpm not hp	23.8
12448	1800	rpm not hp	23.8
12448	1800	rpm not hp	23.8
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12448	1800	rpm not hp	23.8
12448	1800	rpm not hp	23.8
12444	1800	rpm not hp	23.2
12444	1800	rpm not hp	23.2
12444	1800	rpm not hp	23.2
12444	1800	rpm not hp	23.2
12444	1800	rpm not hp	23.2
12444	1800	rpm not hp	23.2
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12444	1800	rpm not hp	23.2
12444	1800	rpm not hp	23.2
12444	1800	rpm not hp	23.2
12444	1800	rpm not hp	23.2
23647	1800	rpm not hp	23.1
23939	1800	rpm not hp	22.54
3501	1800	rpm not hp	22.5
31477	1800	rpm not hp	20.4
31477	1800	rpm not hp	20.4
24871	1800	rpm not hp	19.5
24874	1800	rpm not hp	19.5
24875	1800	rpm not hp	19.5
24876	1800	rpm not hp	19.5
24870	1800	rpm not hp	19.5
23719	1800	rpm not hp	16.9
37727	1800	rpm not hp	16.2
19960	1800	rpm not hp	15.4
19960	1800	rpm not hp	15.4
26695	1800	rpm not hp	15.3
23718	1800	rpm not hp	14.7
23722	1800	rpm not hp	14.5
23722	1800	rpm not hp	14.5
23722	1800	rpm not hp	14.5
23722	1800	rpm not hp	14.5

23722	1800	rpm not hp	14.5
23722	1800	rpm not hp	14.5
25080	1800	rpm not hp	14.5
25080	1800	rpm not hp	14.5
23710	1800	rpm not hp	13.53
23710	1800	rpm not hp	13.53
26468	1800	rpm not hp	13.5
28055	1800	rpm not hp	12.7
27563	1800	rpm not hp	12.5
12450	1800	rpm not hp	12.4
12450	1800	rpm not hp	12.4
12450	1800	rpm not hp	12.4
12450	1800	rpm not hp	12.4
12450	1800	rpm not hp	12.4
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12450	1800	rpm not hp	12.4
12450	1800	rpm not hp	12.4
12450	1800	rpm not hp	12.4
22479	1800	rpm not hp	12.4
26646	1800	rpm not hp	12.3
28123	1800	rpm not hp	12.1
28542	1800	rpm not hp	11.34
26646	1800	rpm not hp	10.7
26647	1800	rpm not hp	10.7
23723	1800	rpm not hp	10.18
25663	1800	rpm not hp	10
24383	1800	rpm not hp	9.3
25663	1800	rpm not hp	9.3
26305	1800	rpm not hp	9.3
23721	1800	rpm not hp	9
23721	1800	rpm not hp	9
12449	1800	rpm not hp	8.7
12449	1800	rpm not hp	8.7
12449	1800	rpm not hp	8.7
12449	1800	rpm not hp	8.7
12449	1800	rpm not hp	8.7

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12449	1800	rpm not hp	8.7
12449	1800	rpm not hp	8.7
28037	1800	rpm not hp	8.5
26647	1800	rpm not hp	8.1
28356	1800	rpm not hp	7.4
26305	1800	rpm not hp	7.4
1223	1800	rpm not hp	7.2
36222	1800	rpm not hp	6.9
37727	1800	rpm not hp	6.8
37727	1800	rpm not hp	6.8
24295	1800	rpm not hp	6.8
25267	1800	rpm not hp	6.3
25267	1800	rpm not hp	6.3

39510	1800	rpm not hp	5.3
39510	1800	rpm not hp	5.3
3617	1800	rpm not hp	4.1
3617	1800	rpm not hp	4.1
24310	1800	rpm not hp	3.3
25663	1800	rpm not hp	1.6
19960	1800	rpm not hp	1
28007	1800	rpm not hp	0.9
39510	1800	rpm not hp	0.77
39510	1800	rpm not hp	0.77
37750	1775		15.9
1252	1755		11.9
1252	1755		11.9
4568	1642		24
1289	1600		16
1289	1600		16
28007	1600		4.5
28007	1600		4.5
28007	1500		8.1
1188	1480		20.4
1237	1480		20.4
35662	1480		19.5
35662	1480		19.5
35662	1480		19.5
34057	1480		19.4
34057	1480		19.4
34057	1480		19.4
1252	1480		6.6
1252	1480		6.6
1425	1478		21.7
1425	1478		21.7
1333	1478		20.4
1158	1478		20.3
4568	1478		20.2
4568	1478		20.2
4568	1478		20.2
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1274	1478		20.1
1276	1478		20.1
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1272	1478		19.7

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1272	1478		19.7
1272	1478		19.7
1272	1478		19.7
1168	1478		19.7
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1332	1478		18.5
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1236	1478		11.8
1221	1478		11.79
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1221	1478		11.79
1221	1478		11.79
4568	1445		33.5
1252	1445		26.9
1158	1445		23.2
1387	1445		12.1
1333	1408		20.4
1333	1408		20.4
1333	1408		20.4
36499	1400	rpm not hp	23.7
36499	1400	rpm not hp	23.7
36499	1400	rpm not hp	23.7
36499	1400	rpm not hp	23.7
36499	1400	rpm not hp	23.7
36499	1400	rpm not hp	23.7
26464	1400		19.4
1333	1400		18.5
1333	1400		18.5
27353	1400	x	17.37
23720	1400		15.1
25845	1400		14.6
3449	1400		14.54

36593	1400		12.3
36593	1400		12.3
26138	1400		12.2
27807	1400		10.9
36499	1400		6.1
36499	1400		6.1
36499	1400		6.1
36499	1400		6.1
1387	1395		27.9
1387	1395		12.1
38978	1380		13.33
37750	1380		12.3
37750	1380		12.3
36553	1380		12.3
38839	1380		12.22
38980	1380		12.13
1272	1362		19.7
1181	1350		19.6
1181	1350		19.6
1250	1350		18
1250	1350		18
1423	1340		25.8
1423	1340		25.8
1423	1340		25.8
25843	1340		19.4
37693	1277		24.7
37693	1277		24.3
1299	1265		24.4
37765	1240		24.7
37693	1240		15.9
1275	1232		16.7
1275	1232		16.7
1275	1232		16.7
35662	1215		16
35662	1215		16
35662	1215		16
20138	1200		21
20139	1200		21
36499	1200		19.2
36499	1200		19.2
1307	1200		12
1307	1200		12
20487	1200		11.1
22568	1200	x	7.5

1425	1184		27.89
1188	1151		25.3
1277	1140		26.5
1147	1100		96
1147	1100		96
1147	1100		96
1147	1100		96
1147	1100		96
1147	1100		96
1147	1100		96
1147	1100		96
1147	1100		96
1147	1100		96
1147	1100		96
1147	1100		96
1147	1100		96
1147	1100		96
1374	1100		20
1325	1085		31.4
1325	1085		31.4
1325	1085		31.4
1412	1085		21
1375	1085		19.05
37750	1085		12
37750	1085		12
1276	1072		14.5
25846	1005		14.6
25847	1005		14.6
3524	1004		18.15
39597	1004		17.98
39597	1004		17.98
36553	1004		17.9
27709	945		17.1
27709	945		17.1
39597	945		16.93
39597	945		16.93
3524	945		16.02
3524	945		16.02
1304	860		15.8
1305	860		15.6
1305	860		15.6
1187	859		90
1252	840		23.4
1158	830		162

1158	830		162
1158	830		162
1280	814		18.7
1188	800		96
38750	800	x	1.9
27948	800	x	0.8
27548	800	x	0.8
27563	800	x	0.8
28055	800	x	0.8
26695	800		0.5
23647	800		0.35
1237	738		10.17
1276	738		10
1202	730		10.56
1192	710		5.9
27353	700	x	2.22
3501	700		0.5
37095	690		10.2
36537	690		10.2
34655	690		10.1
37750	690		6.2
37750	690		6.2
36553	690		6.2
38978	690		3.33
38839	690		3.06
38980	690		3.03
1263	676		9.8
37693	638		24.7
26916	637		12.3
26684	637		12.28
28885	630		12.1
3428	630		11
22429	600		19.2
22422	600		18.8
24283	600		13.6
23707	600		12.75
38839	600		5.32
38839	600		5.32
38839	600		5.32
38980	600		5.28
38980	600		5.28
38980	600		5.28
39541	600		5.28
39541	600		5.28

36222	600		2.2
27082	530		13.3
1229	520		9.1
1252	513		4.3
1252	513		4.3
1252	513		4.3
24335	510		18.5
24328	510		18.5
24336	509		18.4
2008	465		22.4
1148	450		3.5
4659	440		11.4
4659	440		11.4
27231	440		9.1
24441	440		8.2
24441	440		8.2
34763	420		14.1
34763	420		14.1
39167	420		13.65
37995	420		13.5
37995	420		13.5
37553	420		13.5
37553	420		13.5
37827	420		13.5
37827	420		13.5
38038	420		13.2
38038	420		13.2
28853	408		7.9
23708	400		14.8
1419	400		12.5
23796	400		11.58
23796	400		11.58
23796	400		11.58
23796	400		11.58
23796	400		11.58
23796	400		11.58
23796	400		11.58
30029	400		8.9
29300	400		8.1
38839	400		3.54
38980	400		3.52
33163	400		3.5
38978	400		2.39
38978	400		2.39

38978	400		2.39
38978	400		2.39
1158	390		2.94
1170	384		6.5
1171	384		6.5
1173	384		6.4
28429	384		6.3
28429	384		6.3
28542	384		6.3
28542	384		6.3
1190	383		12.3
39167	380		3.43
38038	380		3.3
1364	365		7
1329	360		16.29
23709	360		12.54
23709	360		12.54
23709	360		12.54
23709	360		12.54
23709	360		12.54
23709	360		12.54
23709	360		12.54
23709	360		12.54
23712	360		10.3
23712	360		10.3
23712	360		10.3
23712	360		10.3
23712	360		10.3
23712	360		10.3
23712	360		10.3
23712	360		10.3
23712	360		10.3
23712	360		10.3
23712	360		10.3
23712	360		10.3
23712	360		10.3
28356	360	x	4.1
31477	360		4
31477	360		4
34636	340		6.5
33642	340		4.1
33642	340		4.1
28037	333		30.6
1205	314		13.3

1216	310		30.4
1248	310		10.57
1202	280		12.17
1395	269		24.7
1205	240		16.5
1295	239		44.2
1202	230		6.67
1202	230		6.67
26782	220		1.8
27632	220		1
33642	211		4.1
33642	211		4.1
34819	211		4.1
34819	211		4.1
24063	203		1.96
24063	203		1.96
38978	203		0.98
27709	203		0.9
27709	203		0.9
27709	203		0.9
27709	203		0.9
1377	200		38.7
1306	192		5.42
29231	188		19.2
38576	175		22.48
29231	175		4.3
25273	175		2.7
25273	175		2.7
25273	175		2.7
25273	175		2.7
25273	175		2.7
25273	175		2.7
25273	175		2.7
25273	175		2.7
25273	175		2.7
27870	175		2.3
39541	175		1.54
39541	175		1.54
39541	175		0.115
39541	175		0.115
1287	163		29.89
1287	163		29.89
1287	163		29.89
26791	163		7.4

1162	163		2.35
1162	163		2.35
1162	163		2.35
1328	150		20.6
36366	150		1.3
21666	149		23
29887	145		24.2
1410	145		24.1
37841	145		22.3
37841	145		22.3
36366	143		9.6
28640	135		15.2
27721	127		24.8
1197	125		13.3
28914	124		9.1
39121	124		9.02
28123	124		9
1254	120		17.79
28123	118		13.7
38586	118		12.4
33163	118		4.7
28640	118		1.9
38978	118		0.57
38980	118		0.48
38839	118		0.48
28102	113.2		9.5
1262	106		16
27077	103		9.7
1217	100		9.6
1217	100		9.6
29300	99		2.7
28631	99		1.7
1372	95		15.86
1373	95		15.86
29776	95		15.6
29898	95		15.5
1376	95		14.39
2131	95		12.8
38576	95		12.21
28914	95		12.1
1391	95		10
30908	95		10
26791	95		9.3
26468	92		5.5

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29438	91		6.9
29439	91		6.9
29440	91		6.9
29441	91		6.6
1330	90		21.2
27671	90		10.4
26647	89.1		1.2
26647	89.1		1.2
26791	89.1		1.2
26916	89.1		1.2
26916	89.1		1.2
36537	87		0.39
27870	84		8
39121	84		7.86
3399	84		7.3
3399	84		7.3
3399	84		7.3
3399	84		7.3
3399	84		7.3
3399	84		7.3
3399	84		7.3
3399	84		7.3
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3399	84		7.3
3399	84		7.3
3399	84		7.3
3399	84		7.3
29300	75		7.6
28007	74		1.3
30686	68		7.9
2008	68		7.6
37164	68		7.6
37164	68		7.6
28180	68		7.38
1364	68		6.8
1205	68		3.7
1205	68		3.7
27910	67		7.4
1285	67		3.29
28313	63		8.2
28037	63		8.2
28037	63		4.3
26916	60.8		9.3
28313	53		4.3
28037	53		2.3
26782	52		5
37841	49		6.2
37841	49		6.2
29300	46		2.6
28037	45		5.8
24383	45		4.5
24383	45		4.5
26684	45		2.8
1287	40		29.89
1248	40		4
1223	38		2.7
1205	38		1.4
24329	36.5	wrong units, no HP, but large Nox contribution	18.4
1287	35		3.59
1162	35		3.56
26138	33		1.7
27671	31		0.5
25847	27		5.4
1217	26		0.25

1217	26		0.25
25273	25		2.3
28313	24		2.6
28313	24		2.6
1262	24		2.29
37164	24		1.1
30908	23.6		2.2
30686	23.6		2.2
30686	23.6		1.8
38586	21.4		12.4
30686	21.4		2.3
39167	21.4		2.3
31477	21.4		2.1
31477	21.4		2.1
39167	20		2.22
23710	20		1.84
23718	20		1.8
23719	20		1.8
23722	20		1.8
23720	20		1.8
25080	20		1.8
23721	20		1.8
23712	20		1.8
24441	20		1.8
27870	20		0.6
25267	20		0.5
1364	20		0.5
1364	20		0.5
21666	19		0.9
1329	18		0.6
1329	18		0.6
26782	16		0.6
39167	15.8		2.1
37727	15.8		1.9
28102	15		0.6
38576	14		12.21
27632	10.3		0.4
1364	2	wrong units, no HP, but large Nox contribution	0.9
1162	1	wrong units, no HP, but large Nox contribution	0.11
1287	1	wrong units, no HP, but large Nox contribution	0.1
1175	0	no hp, high Nox	47

33097	0	no hp, high Nox	18.8
26126	0	no hp, high Nox	18.3
37029	0	no hp, high Nox	13.3
37029	0	no hp, high Nox	13.3
26760	0	no hp, high Nox	10.67
34892	0	no hp, high Nox	10.6
32517	0	no hp, high Nox	10.1
35198	0	no hp, high Nox	9.7
27052	0	no hp, high Nox	9.4
12449	0	no hp, high Nox	8.7
12449	0	no hp, high Nox	8.7
12449	0	no hp, high Nox	8.7
1328	0	no hp, high Nox	8.6
1328	0	no hp, high Nox	8.2
1328	0	no hp, high Nox	8.2
34598	0	no hp, high Nox	7.3
34523	0	no hp, high Nox	7.3
34637	0	no hp, high Nox	7.3
34605	0	no hp, high Nox	6.7
32174	0	no hp, high Nox	6.6
32498	0	no hp, high Nox	6.6
34650	0	no hp, high Nox	6.6
34696	0	no hp, high Nox	6.6
27052	0	no hp, high Nox	4.93
34046	0	no hp, high Nox	4.1
34248	0	no hp, high Nox	3.72
32216	0	no hp, high Nox	3.54
32216	0	no hp, high Nox	3.54
34046	0	no hp, high Nox	2.4
34523	0	no hp, high Nox	2.4
31477	0	no hp, high Nox	2.2
31477	0	no hp, high Nox	2.2
32174	0	no hp, high Nox	2.1
23707	0	no hp, high Nox	1.84
23723	0	no hp, high Nox	1.84
23725	0	no hp, high Nox	1.84
23726	0	no hp, high Nox	1.84
23796	0	no hp, high Nox	1.84
23797	0	no hp, high Nox	1.84
31054	0	no hp, high Nox	1.84
25273	0	no hp, high Nox	1.8
23708	0	no hp, high Nox	1.8
3428	0	no hp, high Nox	1.8
26760	0	no hp, high Nox	1.19

34892	0	no hp, high Nox	1
34892	0	no hp, high Nox	1
34892	0	no hp, high Nox	1
27377	1800	rpm not hp	22.5
27377	1800	rpm not hp	12.3
33079	1800	rpm not hp	7.1
1110	1680		30.7
1110	1680		30.7
36717	1480		19.5361
1110	1478		27
38153	1478		19.55
38026	1400	rpm not hp	23.66
36455	1400		6.1
36455	1400		6.1
38026	1400		3.05
38965	1380		13.33
38026	1340		47
38649	1340		23.71
38649	1340		23.71
1110	1232		18.6
36455	1200		21
36455	1200		21
36717	805		2.974
38026	690		6.1
38965	690		3.33
38649	690		3.1
38649	690		3.1
36717	690		3.0362
38153	633		2.79
38965	600		5.79
38965	600		5.79
39542	600		5.28
39542	600		5.28
38649	400		6.5
38026	400		6.48
38153	400		3.53
36717	400		3.5202
33079	380		3.7
38153	211		0.93
39542	175		1.54
39542	175		1.54
38965	118		0.57
38649	118		0.48
36717	118		0.4765

33079	110		2.1
29629	95		9
39542	87.1		0.115
39542	87.1		0.115
38026	87		1.1
38649	87		0.14
38649	87		0.14
38649	87		0.14
38649	87		0.14
38649	87		0.14
38649	87		0.14
38649	87		0.14
38649	87		0.14
1111	80.4		14.9
33686	0	no hp, high Nox	10.5
33686	0	no hp, high Nox	1
33686	0	no hp, high Nox	1

Date 28 July 2021
New Mexico Oil and Gas Association
Attn: John Smitherman

SUBJECT: Valor EPC Study: NMAC 20.2.50.114, Compressor Seals

Dear Mr. Smitherman,

Valor EPC is pleased to provide this study and supporting evidence on the subject of Compressor Seals in response to the proposed rules to Title 20 Chapter 2 Part 50 (20.2.50 NMAC) paragraph 114. The below study represents Valor EPC's professional opinion based on years of experience and supporting data, to the maximum extent possible, within the required schedule.

Executive Summary

New Mexico Oil and Gas Association (NMOGA) has asked Valor EPC to analyze the New Mexico Environment Department (NMED) Proposed Rule 20.3.50.114 "Compressor Seals" and associated documents and draft a technical commentary. The commentary is to identify new requirements that are technically infeasible and/or impractical from an economic standpoint. Valor EPC suggests that NMOGA propose revisions to the proposed applicability and emissions standards for this part as follows:

VOC emissions from compressors (reciprocating and centrifugal) account for a minuscule amount of the overall VOC emissions per NMED. In total, it is estimated that 0.006% of the total VOC emissions come from compressor seals. Because of this, the rule is negligible in reducing ground level ozone formation and redundant as compressor seals are already regulated by OOOO. Additionally, NMED has established very prescriptive requirements to collect gas under negative pressure close vent systems. It is recommended that this rule is removed. Alternatively, at a minimum, the prescriptive requirements of closed vent system should be removed and aligned with OOOO, allowing allow operators to determine the most effective and economic method to collect vent gas.

1 New Mexico Environment Department Report and Data Review

20.2.50.114

- Valor recommends that the Compressor Seals sections be completely removed from the proposed rule. According to the NMED spreadsheet, total emissions (VOCs) from compressor seals, both reciprocating and centrifugal is 0.006% of total VOC emissions from compression (figure 1), which is estimated at 13 tons/year. The proposed rules would at best, per the NMED provided analysis, only reduce the tonnage by 6 tons/year, or 0.005% of the calculated VOCs post rule (figure 2).
- An air quality scientist provided testimony to discuss the disproportionate impact of NOx versus VOCs on ozone formation. Utilizing ozone regulatory monitors across NM, ozone formation attributable to NM oil and gas from either NOx and VOC emissions can be quantified. This is possible utilizing CAMx source apportionment which separately tracks ozone that is formed under NOx limited and VOC limited conditions. At all the monitors, the contribution of the NOx emissions is much greater than the contribution of the VOC emissions. Figure 1 shows a histogram

of ozone contribution from NOx and VOCs. The maximum impact of the NOx emissions is 2.60 ppb and the maximum of the VOC emissions is 0.5 ppb and the average impact 0.73 ppb NOx and 0.10 ppb VOC. This indicates that NOx contributes to ozone formation 5x- 7x more than VOCs.[1] The argument that reducing the extremely low VOC emissions from compressor seals will have essentially no affect on ozone formation.

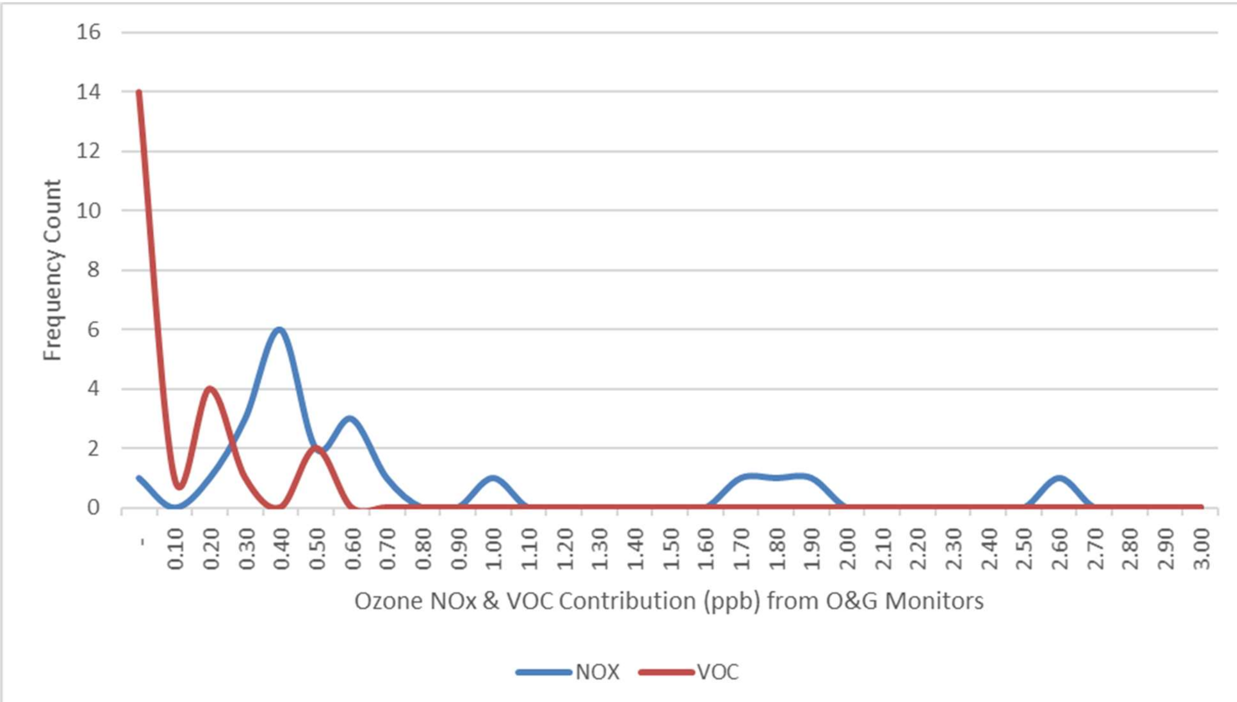

Figure 1: Histogram of NOx and VOC contribution at monitors across NM from D. McNally testimony[1]

[1] Dennis McNally, Alpine Geophysics, Testimony dated July 28, 2021.

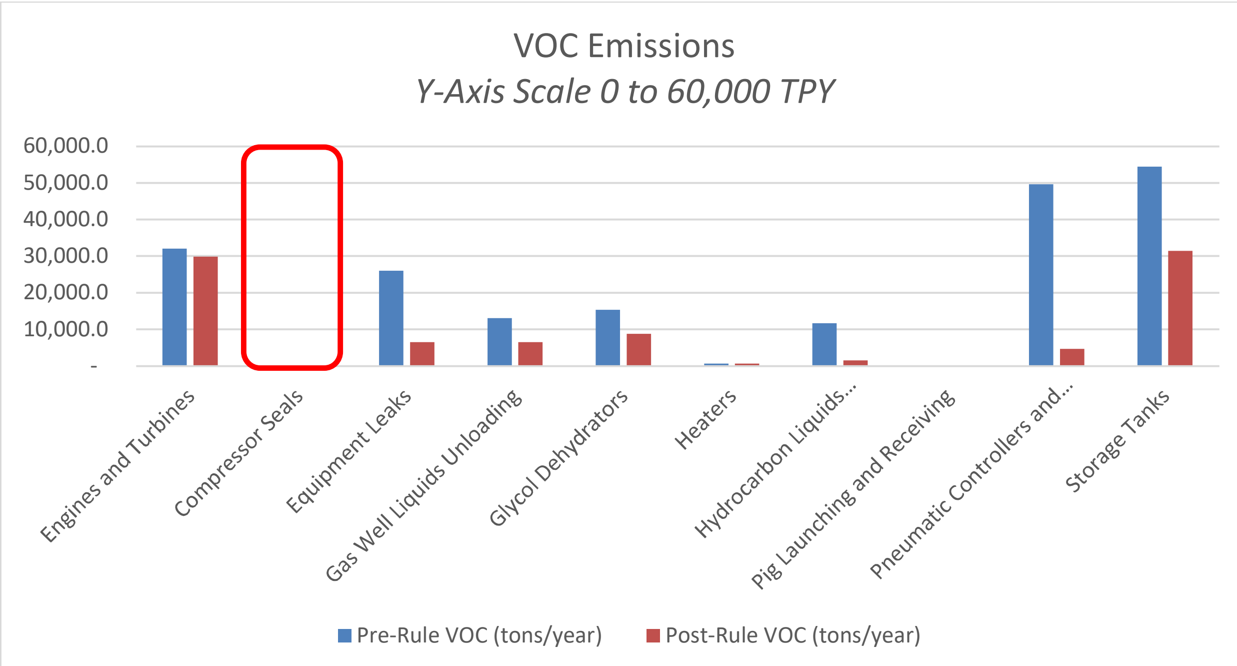

Figure 2: Chart showing predicted VOC emission levels pre and post NMAC proposed rule.

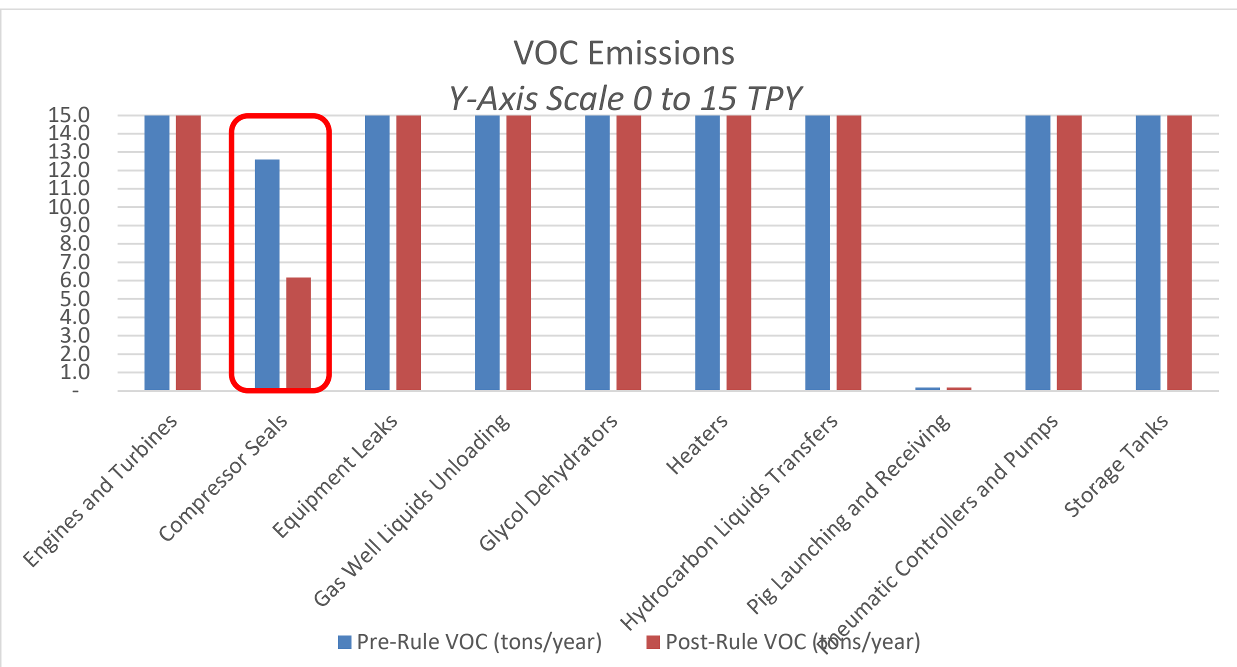

Figure 3: The two charts show the miniscule reductions achieved by gas compressor venting. This imposes a significant regulatory burden without any benefit. On a percentage basis, VOC reductions by compressor vent control is outside of any reasonable accuracy.

20.2.50.114 (B) Part 2 (a)

- Because it not common practice to collect the gas from reciprocating compressor seals there is no industry standard for implementation. Because of this, operators will just elect to replace the reciprocating compressor rod packing at the specified time or hour interval (every 26,000 hours of compressor operation, or every 36 months, whichever is reached later) making the rule irrelevant.

- For compressors located in buildings, venting gas creates a high fire risk such that operators already monitor packing and seals to mitigate the risk and keep gas detectors from alarming.
- This rule is redundant as OOOOa already has similar rules in place.
- Valor recommends striking this section or at a minimum remove the "collect compressor vents under negative pressure" statement allowing operators to determine most effective method for reducing venting. Valor believes that "negative pressure" is overly prescriptive, could result in oxygen entrainment (safety concern), and does not allow flexibility for new technology or new facility concepts. Instead, Valor recommends that the top-level requirement should be to capture the vapors in a closed vent system and leave it up to the operator to determine the best the method to execute.

2 References

Applicable NMAC Paragraphs
20.2.50.114

Applicable NMED Documents
The following NMED documents were evaluated (reference https://www.env.nm.gov/air-quality/ozone-precursor-rule-hearing/)

1. Emission Inventory Reductions (06-08-2021).xlsx

We look forward to discussing this report with you in more detail.

Sincerely,

Justin M. Lisowski P.E.
Senior Project Engineer & Facility Specialist
Valor EPC | ph: 303.803.3152 | email: justin.lisowski@valorepc.com

Appendix A4 – Direct Testimony of Dennis McNally

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION
20.2.50 **No. EIB 21-27 (R)**
Oil and Gas Sector – Ozone Precursor Pollutants

TESTIMONY OF DENNIS MCNALLY

I. BACKGROUND

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Dennis E. McNally, and my address is 7341 Poppy Way, Arvada, Colorado 80007.

Q. WHAT IS YOUR INVOLVEMENT IN THIS PROCEEDING?

A. I am a Senior Scientist with Alpine Geophysics, LLC (Alpine Geophysics), and I am reviewing the photochemical modeling conducted to support this rulemaking.

Q. WHAT IS YOUR OCCUPATION?

A. I am a consulting air quality scientist.

Q. HOW LONG HAVE YOU HELD YOUR CURRENT POSITION?

A. I have held this position at Alpine Geophysics since 1990.

Q. WHAT ARE YOUR RESPONSIBILITIES AT ALPINE GEOPHYSICS?

A. At Alpine Geophysics, my responsibilities include application and analysis of advanced photochemical and meteorological computer models.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I have a Bachelor of Science in Chemical Engineering from the University of Colorado and a Master of Science in Atmospheric Science from the University of California.

Q. PLEASE BRIEFLY SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. I began my atmospheric modeling career while an undergraduate at the University of Colorado working as a student assistant for the National Center for Atmospheric Research

(NCAR) working to develop improved chemical mechanisms for use in photochemical air quality models. After graduating, I worked for four years with Radian Corporation establishing an advanced modeling program and began my graduate studies at the University of California. In 1990 I began working with Alpine Geophysics in application and analysis of advanced photochemical and meteorological models.

Q. DO YOU HAVE ANY PROFESSIONAL AFFILIATIONS?

A. Yes.

Q. WHAT ARE THEY?

A. I am a member of the American Chemical Society (ACS).

Q. WHAT ANALYSIS WERE YOU ASKED TO CONDUCT AS PART OF YOUR REVIEW?

A. I was asked to examine the photochemical modeling analysis conducted by the NMED, to determine the appropriateness of the analysis and to assist in interpreting the ozone impacts of the proposed rule.

Q. CAN YOU DESCRIBE WHAT PHOTOCHEMICAL MODELING IS?

A. Photochemical modeling involves simulating the formation of atmospheric pollutants by complex interactions of chemical compounds in the presence of sun light.

Q. PLEASE DESCRIBE YOUR SPECIFIC EXPERIENCE WITH PHOTOCHEMICAL MODELING?

A. I began working on photochemical models in the late 1980's at the NCAR, developing improved chemical mechanisms for a new generation of photochemical models. The chemical mechanism is the "submodel" of the photochemical model that handles the chemical transformations. Since 1990, I have been involved continuously on well over one hundred photochemical modeling studies, primarily in practical application studies for government and industry, across the United States and abroad.

Q. HAVE YOU PERFORMED PHOTOCHEMICAL MODELING OR OTHER MODELING ANALYSES IN THE WESTERN UNITED STATES BEFORE?

A. I have done numerous studies involving photochemical modeling in the Western U.S.

Q. CAN YOU PLEASE DESCRIBE YOUR PRIOR WORK IN THE WEST?

A. I was the lead photochemical modeler for the San Juan County Early Action Compact (EAC) back in 2003-2004 where we applied the CAMx photochemical model to examine ozone attainment issues in San Juan County and the four-corner regions. In addition I have been in working on the team (with Ramboll) since 2003 to develop, evaluate and interpret the photochemical modeling for the Denver/Northern Front Range area and have done a number of projects for the Western Regional Air Partnership (WRAP) and the National Environmental Policy Act (NEPA) photochemical assessments for numerous projects in Utah and Wyoming.

Q. DID YOU REVIEW OTHER MATERIALS IN ANTICIPATION OF YOUR TESTIMONY ?

A. I did.

Q. WHAT MATERIALS DID YOU REVIEW?

A. I reviewed the following documents:

New Mexico Ozone Attainment Initiative Photochemical Modeling Study – Draft Final Air Quality Technical Support Document. Ramboll US Consulting , Inc. and Western States Air Resources Council for New Mexico Environmental Division. May, 2021.

Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Quality Assessment Division. Research Triangle Park, NC. EPA 454/R-18-009. November 29, 2018. (https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf).

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ON THE IMPACT OF THE PROPOSED RULE

A. The ozone air quality benefits of the proposed rule are quite modest, and what impacts the rule does have are primarily the result of the NO_x control measures. Additional controls on oil and gas VOC emissions are not an effective means of controlling ambient ozone levels in New Mexico, except for possibly in a very limited area in northeastern San Juan County.

Q. YOU SAID THAT YOU WERE RETAINED TO REVIEW THE OZONE IMPACTS. WHAT IS OZONE?

A. Ozone is an oxygen compound that consists of three oxygen atoms bound together instead of the typical two atoms in molecular oxygen.

Q. DO OIL AND GAS ACTIVITIES EMIT OZONE DIRECTLY?

A. No.

Q. HOW IS OZONE FORMED IF NOT DIRECTLY EMITTED?

A. Ozone is formed by the complex interactions of VOC with NO_x in the presence of sun light.

Q. HOW DO YOU PREDICT THE LOCATION AND DURATION OF OZONE FORMATION?

A. Ozone formation is typically predicted by the use of photochemical air quality models, including the Comprehensive Air Quality Model with Extensions (CAMx). CAMx is a publicly available photochemical model developed by Ramboll US Consulting Inc. (Ramboll) and widely used for air quality planning across the United States and abroad.

Q. WHAT DO YOU MEAN BY THE TERM "PHOTOCHEMICAL"?

A. By photochemical, I mean that the model includes chemical transformations that are influenced by light.

Q. WHAT IS YOUR PRIOR EXPERIENCE WITH THE CAMX MODEL?

A. I have had extensive use of the CAMx model since it was first developed in the late 1990's. In fact, I was one of the first people outside of the developers to use the model and I have been involved in beta testing and providing suggestions for model improvements ever since.

Q. HOW DOES A PHOTOCHEMICAL MODEL WORK?

A. Photochemical models are comprehensive air quality models that simulate the full range of processes that influence air pollutants. Photochemical models include advection (the bulk movement of air parcels under the predominant wind flow), diffusion (dispersion due to fine scale air movements), chemical transformation and wet and dry deposition. The term "photochemical" specifically refers to the fact that these models are able to simulate the transformation of NO_x and VOC in the presence of sunlight into ozone, and other reaction products.

Q. DID YOU RUN THE PHOTOCHEMICAL MODEL FOR THE PROPOSED RULE?

A. I did not perform new photochemical modeling for this project. My assessment is based on the review of the Technical Support Document prepared by Ramboll and the Western States Air Resources Council (WESTSTAR) for NMED, and my analysis of the photochemical modeling output files supplied by Ramboll.

Q. WHAT IS YOUR ASSESSMENT AS TO THE APPROPRIATENESS OF THE MODELING FOR THE PROPOSED RULE?

A. I agree with the general approach taken to examine the air quality impacts of the proposed rule. Photochemical grid models are the best approach to examine the ozone impacts of emission changes.

The photochemical modeling used meteorology developed by the very credible Weather Research and Forecasting (WRF) model, along with the SMOKE emissions model and other emissions models.

This is the same general approach taken by EPA for the Cross State Air Pollution Rule (CSAPR), for regional haze planning in the west and southeast, and for ozone state implementation plans in Colorado, Texas and other areas across the United States.

The model application included a 4km nest over New Mexico to capture the complex meteorological flows over mountainous terrain and to resolve the spatial patterns of the precursor emissions. The application also included a model performance evaluation against ambient ozone concentrations and I agree with the assessment in the Technical Support Document (TSD) that the "model performance within New Mexico is as good or better than most recent [photochemical grid model] applications (e.g., WRAP-WAQS, EPA 2016v1 and Denver ozone SIP) and appears to be a reliable [photochemical grid model] modeling platform for evaluating emission reduction strategies for reducing ozone concentrations in New Mexico".

Q. YOU SAY THAT YOU AGREE THAT THE MODELING PLATFORM IS APPROPRIATE FOR EVALUATING EMISSION REDUCTION STRATEGIES, BUT WHAT DOES THE MODEL PERFORMANCE EVALUATION SHOW AS FAR AS OZONE CONCENTRATIONS MEASURED AT THE VARIOUS MONITORS? THAT THE MODEL OVERESTIMATES OZONE CONCENTRATIONS AT SOME MONITORS AND UNDERESTIMATES OZONE CONCENTRATIONS AT OTHER MONITORS.

A. The model performance evaluation shows that the model overestimates ozone concentrations at some monitors and underestimates ozone concentrations at other monitors. This is typical. Photochemical models, and the underlying meteorological models, are not perfect, so it is understandable to have some error in the model concentrations. I am more concerned if a model is showing consistent over, or under, estimates since this could be indicative of a systematic error in the model or input data.

To account for the model bias, the EPA "Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5 and Regional Haze" states that photochemical models should be used in a relative sense. The majority of the analyses in the TSD use this approach, and all of the analyses that I have conducted use this approach.

Q. BRIEFLY EXPLAIN HOW A MODEL IS USED IN A RELATIVE SENSE.

A. A model is used in a relative sense by running the model for the base year (2014 in this application) and a future year (2028 in this application). The change in air quality is computed by dividing the future year concentration by the base year concentration. This fractional change is then multiplied by the observed ozone concentration to project the future concentrations.

Q. USING THE EPA SUGGESTED RELATIVE MODELING APPROACH, WHAT ARE THE FORECAST OZONE CONCENTRATIONS IN NEW MEXICO IN 2028?

A. The base year and projected 2028 ozone concentrations are presented in Table 7-1 of the TSD, reproduced below (Table A). Ozone levels are compared to EPA's standard for ozone air quality by calculating a "design value" based on monitored ozone data and scaling the results by the base and future year modeled concentrations. The modeling shows a decrease in ozone concentrations at all monitors across NM with an ozone estimate of 60.8 ppb at Navajo Lake, concentrations from 59.1 to 62.6 ppb in Bernalillo County, and 67.0 ppb at Desert View and 64.0 at Hobbs Jefferson in Southern NM. All monitors are projected to be below the 70 ppb ozone standard.

Table A

Table 7-1. Current year $DVC_{2012-2016}$ and projected 2028 Base Case ozone DVFs at New Mexico monitoring sites within the 4-km NM domain.

AQS_ID	2012-2016 DVC (ppb)	2028 Base DVF Base (ppb)	Difference 2028 DVF minus $DVC_{2012-16}$ (ppb)	Site Name	State	County
Northern New Mexico						
350390026	64.0	60.8	-3.2	Coyote Ranger District	NM	Rio Arriba
350431001	64.0	58.4	-5.6	Bernalillo (E Avenida)	NM	Sandoval
350450009	64.3	61.0	-3.3	Bloomfield	NM	San Juan
350450018	67.0	64.8	-2.2	Navajo Lake	NM	San Juan
350451005	63.7	60.8	-2.9	Substation	NM	San Juan
350490021	64.3	60.6	-3.7	Santa Fe Airport	NM	Santa Fe
Bernalillo County						
350010023	66.3	60.9	-5.4	Del Norte HS	NM	Bernalillo
350010024	68.0	62.3	-5.7	South East Heights	NM	Bernalillo
350010029	66.0	61.0	-5.0	South Valley	NM	Bernalillo
350010032	67.0	62.6	-4.4	Westside	NM	Bernalillo
350011012	65.0	59.1	-5.9	Foothills	NM	Bernalillo
Southern New Mexico						
350130008	66.3	60.0	-6.3	La Union	NM	Doña Ana
350130017	67.0	61.9	-5.1	Sunland Park City Yard	NM	Doña Ana
350130020	67.0	62.3	-4.7	Chaparral	NM	Doña Ana
350130021	72.0	67.0	-5.0	Desert View	NM	Doña Ana
350130022	71.3	66.1	-5.2	Santa Teresa	NM	Doña Ana
350130023	65.0	60.3	-4.7	Solano	NM	Doña Ana
350151005	69.0	66.7	-2.3	Carlsbad	NM	Eddy
350171003	62.0	59.0	-3.0	Chino Copper Smelter	NM	Grant
350250008	66.0	64.0	-2.0	Hobbs Jefferson	NM	Lea
350290003	66.0	62.7	-3.3	Deming Airport	NM	Luna
350610008	66.3	62.2	-4.1	Los Lunas (Los Lentes)	NM	Valencia

The projected ozone concentrations across the modeling domain concentrations from the relative approach are presented below (Figure 7-2 in the TSD) (Figure A). All grid cells in the domain are less than the 70 ppb ozone standard with a peak concentration of 67.9 ppb.

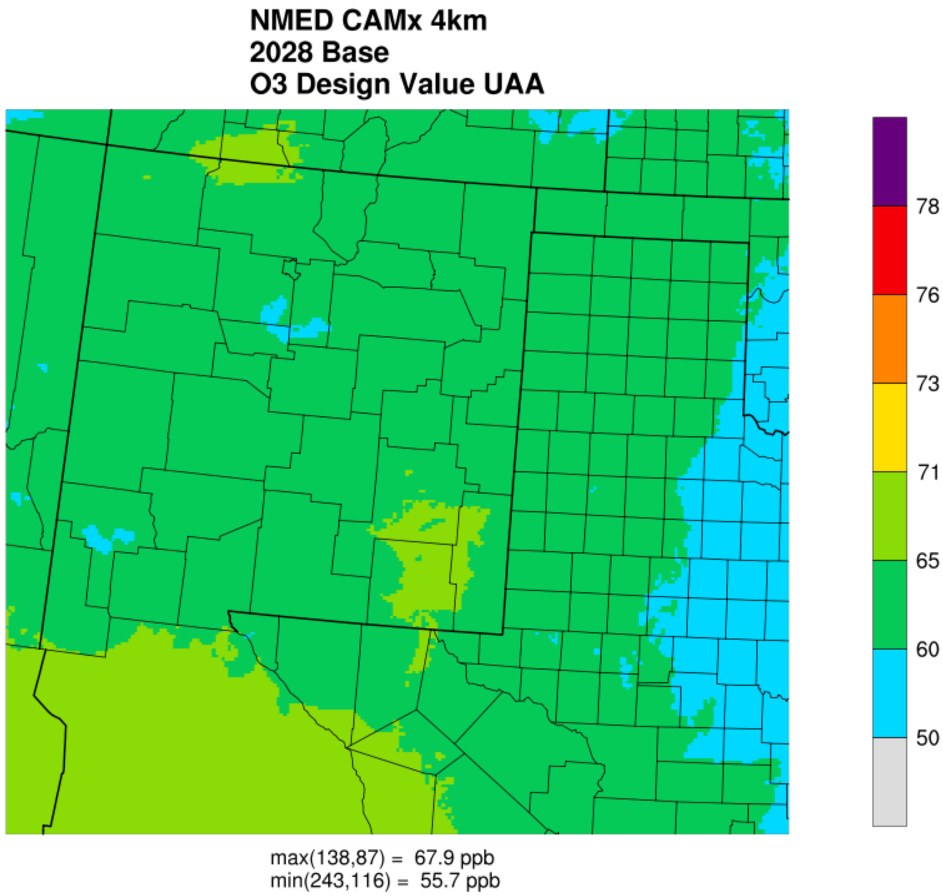

Figure A: Projected 2028 future year ozone project for 2028 Base Case.

Q. YOU SAY THAT YOU AGREE THAT THE MODEL AS APPLIED IS THE CORRECT TOOL FOR EXAMINING THE OZONE IMPACTS OF THE PROPOSED RULE, DO YOU AGREE WITH THE EMISSION REDUCTIONS FROM THE PROPOSED RULE?

A. I have no expertise in the emission impacts of oil and gas control technologies so I have no opinion as to the appropriateness of the emission reductions from the proposed rule.

Q. SINCE PHOTOCHEMICAL MODELING REQUIRES ALL MANMADE AND NATURAL EMISSIONS TO BE INCLUDED IN THE MODELING, PLEASE PRESENT THE BREAKDOWN OF THE VOC AND NOX EMISSIONS USED IN THE NMED 2014 BASE YEAR MODELING.

A. The VOC emissions used in the NMED base year emissions inventory are presented below (Figure B). The emissions are averaged over the modeling period from the model ready emissions. This approach is necessary since some the segments (i.e. lightning NOx and biogenics) are not summarized as annual tons in the TSD. 71% of the VOC emissions are from biogenic emissions, 19% are from oil and gas, with the balance as fires and other manmade emissions.

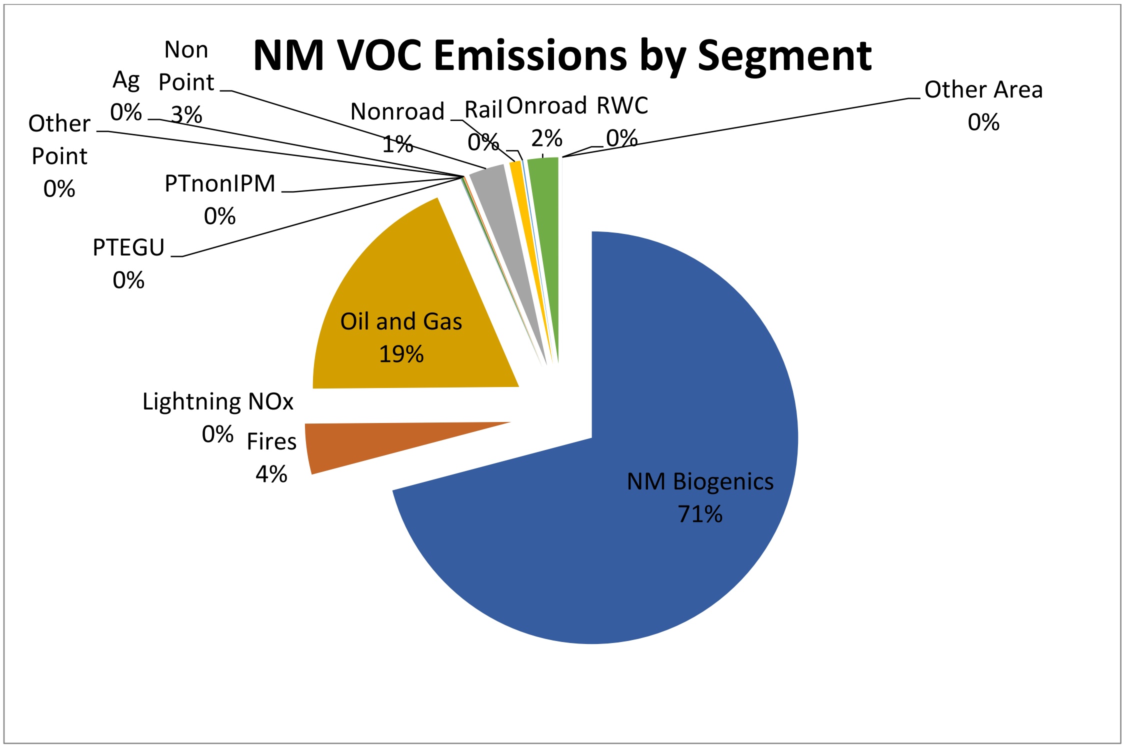

Figure B: Episode average 2014 base case New Mexico VOC emissions by segment.

The NO_x emissions used in the NMED base year emissions inventory follow (Figure C). As with the VOC emissions, the emissions are averaged over the modeling period from the model ready emissions. The largest emission segments are onroad motor vehicles and oil and gas at 24% of the inventory, followed by lightning NOx, Electric Generating Units (EGUs) with the balance from biogenic NOx and other manmade sources.

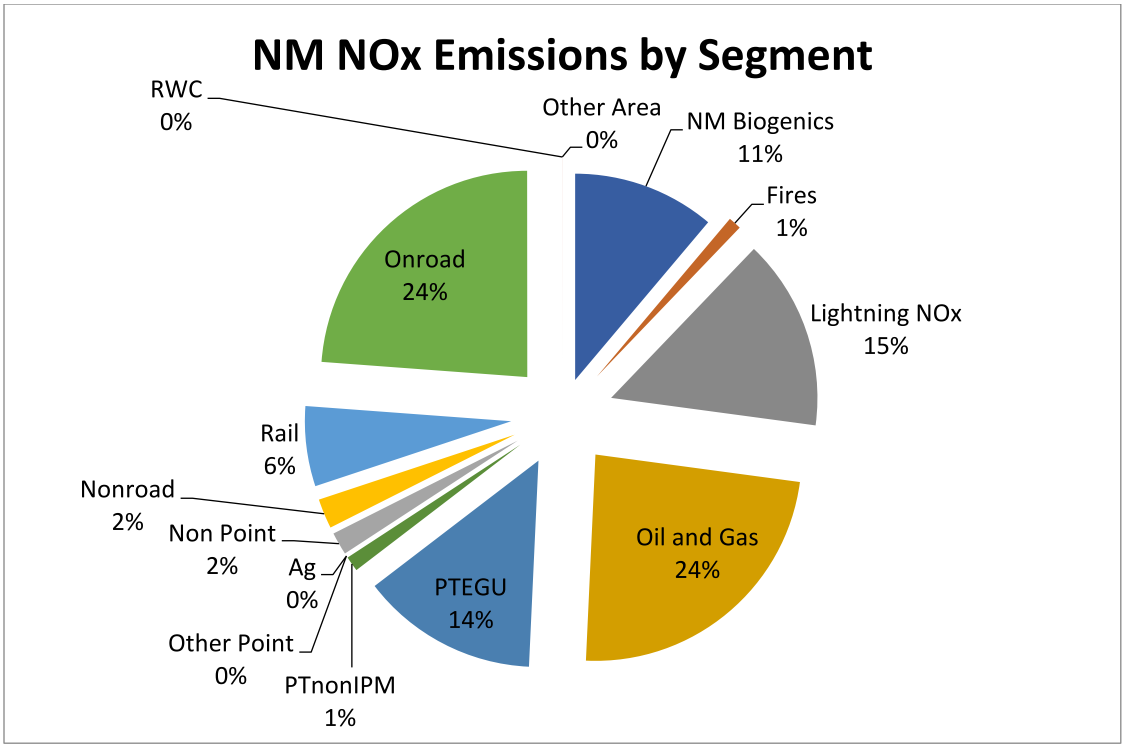

Figure C: Episode average 2014 base case New Mexico NOx emissions by segment.

Q. WHILE YOU HAVE STATED THAT YOU HAVE NO OPINION AS TO THE APPROPRIATNESS OF THE EMISSION REDUCTIONS, PLEASE REMIND US AS TO THE EMISSION REDUCTIONS USED IN THE MODELING.

A. Table 4-9 of the TSD summarizes the emission reductions. The oil and gas NOx emissions are reduced from 102,311 tpy to 56,015 tpy, a 45% reduction and oil and gas VOC emissions are reduced from 211,592 tpy to 105,172 tpy, a 50% reduction.

Q. WHAT IS THE AIR QUALITY IMPACT OF THE PROPOSED RULE?

A. The impacts of the proposed rule are presented in Section 8.1 of the TSD. At the monitors Table 8-1, reproduced below (Table B), show impacts of up to 1.5 ppb at Navajo Lake in the San Juan basin, up to 0.5 ppb in Bernalillo County, and up to 0.7 ppb in the Permian Basin.

Table B

Table 8-1. Observed ozone $DVC_{2012\text{-}2016}$ and projected 2028 ozone DVFs for the 2028 Base Case and 2028 O&G Control strategy and differences in the 2028 ozone DVFs ($DVF_{Cntl} - DVF_{Base}$).

AQS_ID	2012-16 DVC (ppb)	Projected 2028 DVF Base (ppb)	Cntl (ppb)	Cntl - Base	Site Name	State	County
Northern New Mexico							
350390026	64.0	60.8	60.0	-0.8	Coyote Ranger District	NM	Rio Arriba
350431001	64.0	58.4	58.1	-0.3	Bernalillo (E Avenida)	NM	Sandoval
350450009	64.3	61.0	60.2	-0.8	Bloomfield	NM	San Juan
350450018	67.0	64.8	63.3	-1.5	Navajo Lake	NM	San Juan
350451005	63.7	60.8	59.6	-1.2	Substation	NM	San Juan
350490021	64.3	60.6	60.4	-0.2	Santa Fe Airport	NM	Santa Fe
Bernalillo County							
350010023	66.3	60.9	60.7	-0.2	Del Norte HS	NM	Bernalillo
350010024	68.0	62.3	62.0	-0.3	South East Heights	NM	Bernalillo
350010029	66.0	61.0	60.5	-0.5	South Valley	NM	Bernalillo
350010032	67.0	62.6	62.1	-0.5	Westside	NM	Bernalillo
350011012	65.0	59.1	58.8	-0.3	Foothills	NM	Bernalillo
Southern New Mexico							
350130008	66.3	60.0	59.8	-0.2	La Union	NM	Doña Ana
350130017	67.0	61.9	61.8	-0.1	Sunland Park City Yard	NM	Doña Ana
350130020	67.0	62.3	62.2	-0.1	Chaparral	NM	Doña Ana
350130021	72.0	67.0	66.8	-0.2	Desert View	NM	Doña Ana
350130022	71.3	66.1	66.0	-0.1	Santa Teresa	NM	Doña Ana
350130023	65.0	60.3	60.2	-0.1	Solano	NM	Doña Ana
350151005	69.0	66.7	66.4	-0.3	Carlsbad	NM	Eddy
350171003	62.0	59.0	58.9	-0.1	Chino Copper Smelter	NM	Grant
350250008	66.0	64.0	63.3	-0.7	Hobbs Jefferson	NM	Lea
350290003	66.0	62.7	62.5	-0.2	Deming Airport	NM	Luna
350610008	66.3	62.2	62.0	-0.2	Los Lunas (Los Lentes)	NM	Valencia

Q. WITH THOSE LARGE EMISSION REDUCTIONS, PLEASE EXPLAIN WHY THE CHANGES IN OZONE CONCENTRATION ARE SO LOW?

A. That can be explained using the source apportionment modeling performed for the rule analysis and documented in the TSD.

In simplest terms, source apportionment (SA) is an accounting system that tracks ozone as it is formed in the model and apportions the ozone to the emission type and emissions regions where the precursors are emitted. It is a very powerful tool and is often used by EPA for national rule making (i.e. Cross State Air Pollution Rule) and for state implementation plans.

The SA simulation was conducted using the controlled oil and gas emissions, so the contributions presented are after the proposed controls are applied. Due to the non-linearities in ozone formation it is not possible to directly estimate the ozone contributions before the controls are applied using the NMED supplied SA simulation. However with the modest impact of the proposed emission controls (1.5 ppb or less), it is expected that the contributions before the control would not be drastically different.

I have analyzed the SA results supplied by NMED and separately grouped the oil and gas emissions impacts, and all the other manmade emissions impacts in NM and compared it to the future estimated concentrations. The contributions at all monitors are presented in the table below (Table C). The contributions at Navajo Lake, Hobbs Jefferson and Desert View are presented in the following pie charts. In these charts the NM oil and gas contributions are shown in green, the other NM manmade emissions are shown in yellow and the rest of the future year contributions are shown in blue. These show that at Navajo Lake the contribution of all NM sources is 5.5 ppb (Figure D). In other words, if all the emissions within NM were removed, the ozone would still be at 57.8 ppb. At Hobbs Jefferson the NM contribution is 2.8 ppb and the concentration without NM would be 60.5 ppb (Figure E). At Desert View the NM contribution is 2.5 ppb and the ozone without NM would be 64.3 ppb (Figure F). The vast majority of the ozone in NM is from emission sources outside of NM or from biogenic emissions within NM.

Table C: 2028 Control Case, Non-NM manmade contribution, NM Oil and Gas Contribution and NM other manmade contribution at regulatory monitors in NM.

Ozone Monitor ID	Station Name	County	2028 Cntrl Conc,	Non NM Manmade Contrib.	NM O&G Contrib.	NM Other Manmade Contrib.
			PPB	PPB	PPB	PPB
Northern New Mexico						
350390026	Coyote Ranger District	Rio Arriba	60.3	58.7	0.8	0.8
350450009	Bloomfield	San Juan	60.2	55.4	2.3	2.5
350450018	Navajo Lake	San Juan	63.3	57.8	3.0	2.5
350451005	Substation	San Juan	59.6	53.3	2.1	4.2
Central New Mexico						
350010023	Del Norte HS	Bernalillo	60.6	50.4	0.4	9.8
350010024	South East Heights	Bernalillo	61.9	52.5	0.5	8.9
350010029	South Valley	Bernalillo	60.4	52.1	0.7	7.6
350010032	Westside	Bernalillo	61.6	54.7	0.6	6.3
350011012	Foothills	Bernalillo	58.7	50.1	0.4	8.2
350431001	Bernalillo (E Avenida)	Sandoval	58.1	51.3	0.4	6.4
350490021	Santa Fe Airport	Santa Fe	60.4	56.7	0.5	3.2
Southern NM						
350130008	La Union	Dona Ana	59.8	57.8	0.4	1.6
350130017	Sunland Park City Yard	Dona Ana	61.8	59.8	0.3	1.7

Ozone Monitor ID	Station Name	County	2028 Cntrl Conc,	Non NM Manmade Contrib.	NM O&G Contrib.	NM Other Manmade Contrib.
			PPB	PPB	PPB	PPB
350130020	Chaparral	Dona Ana	62.2	61.1	0.2	0.9
350130021	Desert View	Dona Ana	66.8	64.3	0.5	2.0
350130022	Santa Teresa	Dona Ana	66.0	63.7	0.5	1.8
350130023	Solano	Dona Ana	60.2	57.0	0.4	2.8
350151005	Carlsbad	Eddy	66.4	64.6	0.9	0.9
350171003	Chino Copper Smelter	Grant	58.8	58.5	0.1	0.2
350250008	Hobbs Jefferson	Lea	63.3	60.5	2.0	0.8
350290003	Deming Airport	Luna	62.6	60.9	0.3	1.4
350610008	Los Lunas (Los Lentes)	Valencia	62.0	58.4	0.5	3.1

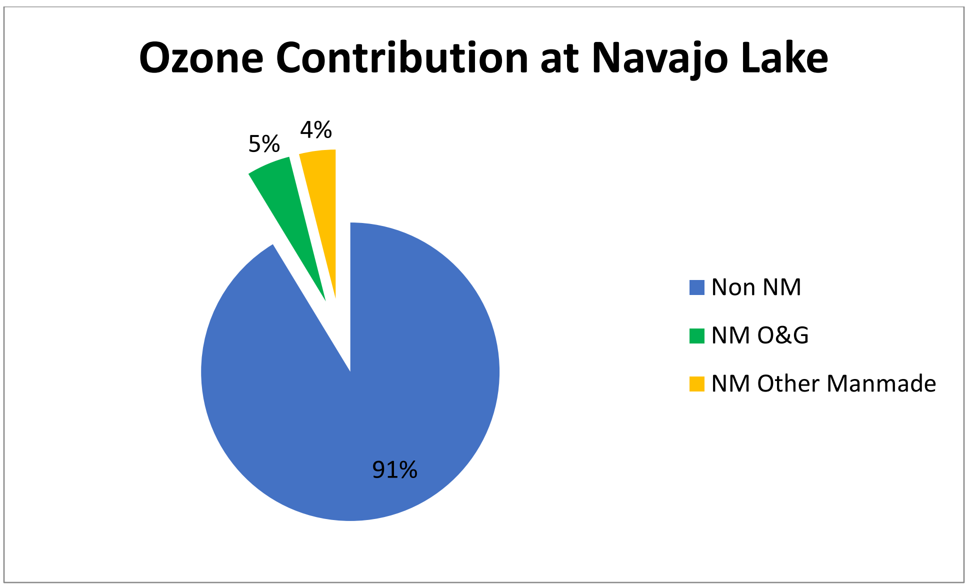

Figure D: Ozone design value contribution of Non-NM manmade, NM oil and gas and NM other manmade at the Navajo Lake monitor.

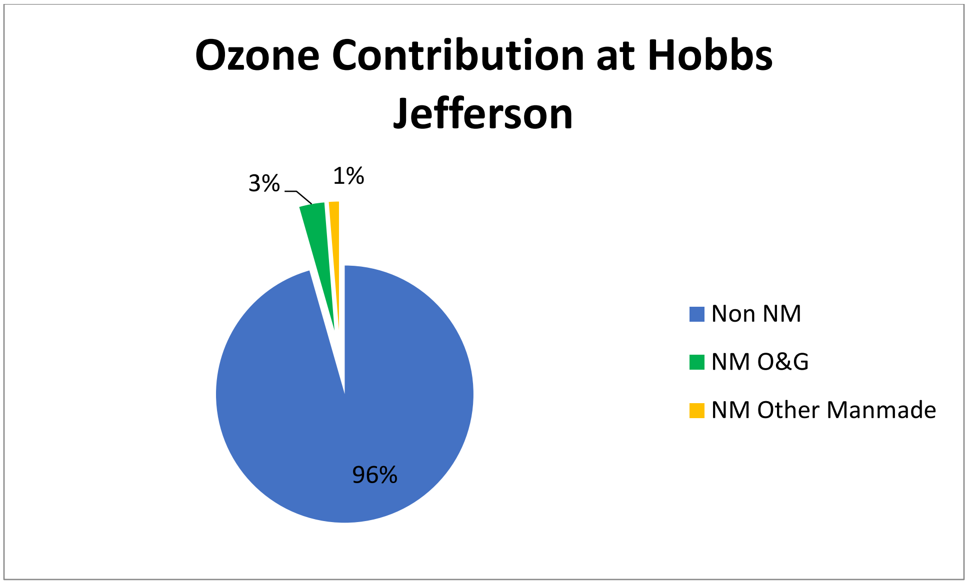

Figure E: Ozone design value contribution of Non-NM manmade, NM oil and gas and NM other manmade at the Hobbs Jefferson monitor.

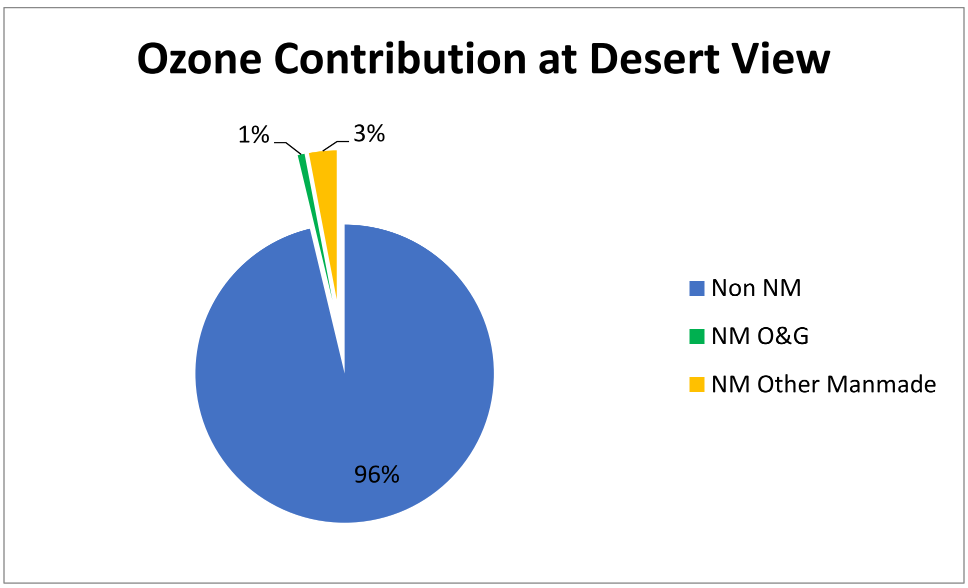

Figure F: Ozone design value contribution of Non-NM manmade, NM oil and gas and NM other manmade at the Desert View monitor.

Q. THE EMISSIONS REDUCTIONS FROM THE PROPOSED RULE IMPACT BOTH VOC AND NOX EMISSIONS. CAN YOU CALCULATE HOW MUCH OF THE EMISSION REDUCTIONS ARE FROM VOC AND NOX EMISSIONS?

A. Using the modeling that was conducted for NMED it is not possible to directly calculate the separate contribution of the VOC and NO_x emission reductions. However, it is possible to separately calculate how much ozone is attributable to oil and gas NO_x and VOC emissions after the proposed emission reductions have been applied. This is possible because the CAMx source apportionment separately tracks ozone formed under NO_x limited (sensitive to NOx emissions) and VOC limited (sensitive to VOC emissions) conditions. The following table (Table D) presents the ozone attributable to NM oil and gas NO_x and VOC emissions, and the contribution per ton of emissions at each ozone regulatory monitor in NM. At all monitors the contribution of the NO_x emissions is much greater than the contribution of the VOC emissions. At the Coyote Ranger District monitor in Northern NM the contribution of NM oil and gas VOC emissions is 0.1 ppb, at the other monitors the VOC contribution is 0.3 to 0.5 ppb. In Central NM the NM oil and gas VOC emissions contribute over 0.1 ppb at two monitors, less than 0.1 ppb at 5 monitors, with a peak of 0.1 ppb at the Santa Fe Airport. In Southern NM the NM oil and gas VOC emissions contribute 0.1 ppb at 4 monitors, and less than 0.1 ppb at the other 7 monitors. Additional controls on oil and gas VOC emissions are not an effective means of controlling ambient ozone levels in New Mexico, except for possibly in a very limited area in northeastern San Juan County.

Table D: New Mexico oil and gas NOx and VOC emissions contributions after the proposed emission reductions at regulatory monitors in NM.

Ozone Monitor ID	Station Name	County	NM O&G NOx Contrib.	NM O&G VOC Contrib.
			PPB	PPB
Northern New Mexico				
350390026	Coyote Ranger District	Rio Arriba	0.7	0.1
350450009	Bloomfield	San Juan	1.9	0.3
350450018	Navajo Lake	San Juan	2.6	0.5
350451005	Substation	San Juan	1.6	0.5
Central New Mexico				
350010023	Del Norte HS	Bernalillo	0.4	0.0
350010024	South East Heights	Bernalillo	0.4	0.0
350010029	South Valley	Bernalillo	0.6	0.0
350010032	Westside	Bernalillo	0.6	0.1
350011012	Foothills	Bernalillo	0.3	0.0
350431001	Bernalillo (E Avenida)	Sandoval	0.4	0.0
350490021	Santa Fe Airport	Santa Fe	0.5	0.1
Southern New Mexico				
350130008	La Union	Dona Ana	0.4	0.0
350130017	Sunland Park City Yard	Dona Ana	0.3	0.0
350130020	Chaparral	Dona Ana	0.2	0.0
350130021	Desert View	Dona Ana	0.4	0.1
350130022	Santa Teresa	Dona Ana	0.5	0.1
350130023	Solano	Dona Ana	0.4	0.0
350151005	Carlsbad	Eddy	0.9	0.1
350171003	Chino Copper Smelter	Grant	0.1	0.0
350250008	Hobbs Jefferson	Lea	1.9	0.0

Ozone Monitor ID	Station Name	County	NM O&G NOx Contrib.	NM O&G VOC Contrib.
			PPB	PPB
350290003	Deming Airport	Luna	0.3	0.0
350610008	Los Lunas (Los Lentes)	Valencia	0.5	0.1

The next figure (Figure G) is a spatial view of the relative impact approach showing the ozone attributable to NM oil and gas NO_x emissions, followed by the ozone attributable to NM oil and gas VOC emissions. Note how small the contributions are from the VOC emissions. The impacts only exceed 0.10 ppb, one 700th of the standard, in a small portion of the San Juan Basin. The maximum impact of the NOx emissions is 4.2 ppb and the maximum of the VOC emissions is 0.60 ppb.

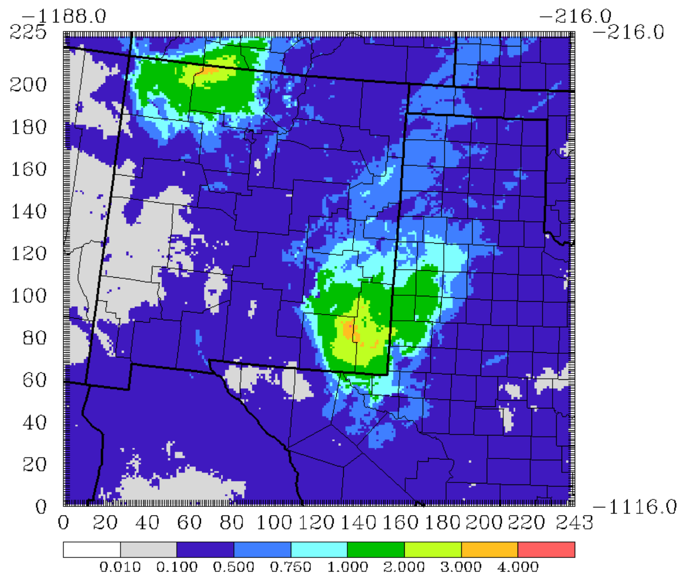

Figure G: Relative impact analysis ozone attributable to NM oil and gas NO_x emissions.

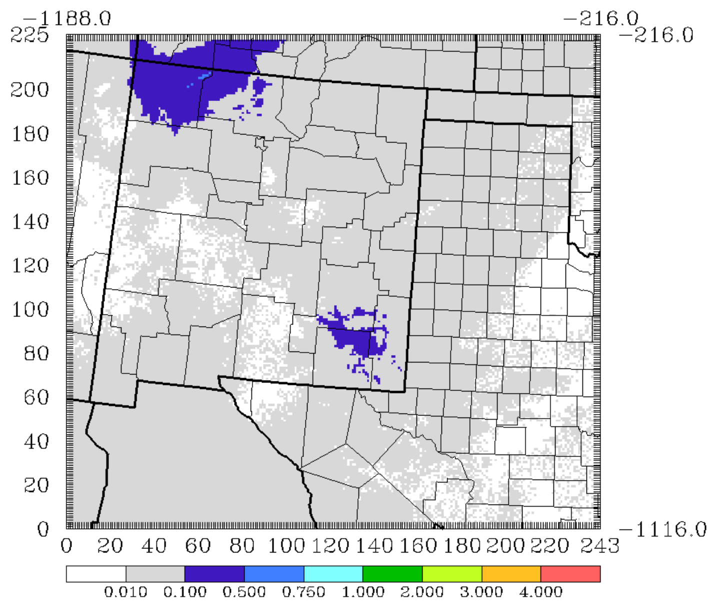

Figure H: Relative impact analysis ozone attributable to NM oil and gas VOC emissions.

Q. IT SOUNDS LIKE THE IMPACT OF THE NEW MEXICO OIL AND GAS VOC EMISSIONS IS QUITE SMALL. OUR EMISSIONS EXPERTS HAVE DETERMINED THAT THE EMISSIONS USED IN THE PHOTOCHEMICAL MODELING FOR THE PROPOSED RULE DID NOT INCLUDE THE NOX EMISSIONS INCREASES FROM THE PROPOSED VOC CONTROLS. WOULD NOT INCLUDING THE EXTRA NOX EMISSIONS FROM THE VOC CONTROLS INFLUENCE THE IMPACT OF THE PROPOSED RULE?

A. Not including the excess NOx emissions from the VOC controls would influence the impact of the proposed rule. The NMED SA simulation showed that 56,015 tpy of oil and gas NOx emissions had much more influence on ozone concentrations than 105,172 tpy of oil and gas VOC emissions. NOx emissions increases would reduce any ozone benefit from the VOC controls, and could worsen the ozone air quality.

Q. NOW THAT YOU HAVE COMPLETED YOUR TESTIMONY, PLEASE REPEAT YOUR CONCLUSIONS ON THE IMPACT OF THE PROPOSED RULE

A. The ozone air quality benefits of the proposed rule are quite modest, and what impacts the rule does have are primarily the result of the NO_x control measures. Additional controls on oil and gas VOC emissions are not an effective means of controlling ambient ozone levels in New Mexico, except for possibly in a very limited area in northeastern San Juan County.

By: /s/ Dennis McNally
Dennis McNally

Appendix A5 – Direct Testimony of Ken Nichols

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION
20.2.50 **No. EIB 21-27 (R)**
Oil and Gas Sector – Ozone Precursor Pollutants

TESTIMONY OF KEN NICHOLS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. Kenneth Nichols
Tetra Tech
8911 N. Capital of Texas Highway Suite 2310
Austin, Texas 78759

Q. WHAT IS YOUR INVOLVEMENT IN THIS PROCEEDING?

A. I was asked to assist the New Mexico Oil and Gas Association (NMOGA) with technical testimony on produced water recycling issues in New Mexico and under the proposed Part 50 ozone attainment initiative rule.

Q. WHAT IS YOUR OCCUPATION?

A. I am a professional engineer (TX, 91095) and Class D Water Operator (TX, WO0046576). I have two roles at Tetra Tech. I serve as a Regional Water Team Leader for Tetra Tech's OGA group and as National Practice Leader for Geologic Carbon Sequestration.

Q. HOW LONG HAVE YOU HELD YOUR CURRENT POSITION?

A. I was hired by Tetra Tech as the Regional Water Team Leader in August 2018, approximately 3 years. My role related to carbon sequestration began in March, approximately 3 months ago.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I attended the University of Illinois at Urbana/Champaign. I earned a bachelor's degree in Civil Engineering in 1995 and a master's degree in Civil Engineering in 1997. My coursework focused on water and environmental engineering.

Q. PLEASE BRIEFLY SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. Illinois State Water Survey – Research Assistant
Dowell Schlumberger – Field Engineer
CH2M HILL – Project Engineer – Water
HDR – Project Manager – Water
CH2M HILL – Global Technology Leader – Water for Upstream Oil and Gas
Devon Energy – Water Management Coordinator, US Division
Tetra Tech – National Practice Leader Geologic Carbon Sequestration and Regional Water Leader

Q. WHAT ARE YOUR PROFESSIONAL AFFILIATIONS, IF ANY?

A. Society of Petroleum Engineers (SPE)
National Groundwater Association (NGWA)
American Water Works Association (AWWA)
South Central Membrane Association (SCMA)

Q. WHAT HAVE YOU BEEN ASKED TO ADDRESS IN YOUR TESTIMONY BEFORE THE BOARD?

A. I have been asked to provide testimony related to my experience on water recycling, specifically related to operations and my opinion of potential impacts of the proposed rule on water recycling operations.

Q. WHAT IS PRODUCED WATER?

A. Produced water is water that is recovered from an oil or gas well. Based on my experience, this includes both water that was injected into the well during hydraulic fracturing operations and water that was originally present in the formation. Rates of recovery and water quality vary by well and over the life of individual wells.

Q. HOW IS PRODUCED WATER RECYCLED IN NEW MEXICO?

A. There are many treatment technologies and management practices related to produced water recycling. Specific activities vary by operator and by well. Based on my experience, the most common approach to recycling produced water includes transportation of the water, treatment of the water, and storage of the water. Initial separation of hydrocarbons and water generally occurs at production facilities. Depending on the specific operational needs, water is moved in pipe, layflat hose, or trucks to disposal or recycling facilities. Treatment of the water generally occurs to remove residual oil and solids using tanks and filters. If the water is going to be recycled, additional treatment may occur to meet water quality specifications for the operator and frac service company. Storage of the water prior to beginning the hydraulic fracturing operation reduces operational risks related to water supply, reduces the required treatment capacity (rate), and allows more water to be recycled.

Q. DOES RECYCLING PRODUCED WATER MINIMIZE USE OF SCARCE FRESH WATER?

A. Yes, recycling reduces the use of scarce fresh water. Each barrel recycled saves a barrel of fresh water.

Q. HOW IMPORTANT IS PRODUCED WATER RECYCLING TO BOTH NEW MEXICO AND THE OIL AND GAS INDUSTRY?

A. Recycling produced water is extremely important to New Mexico and the industry. Each barrel recycled saves a barrel of fresh water. Additionally, recycling reduces water disposal volumes into finite disposal zones, prolonging the operational lives of existing salt water disposal zones.

Q. WHAT WILL HAPPEN TO THE PRODUCED WATER RECYCLING INDUSTRY IF THE PROPOSED PART 50 RULE IS ADOPTED?

A. In my opinion, the rule will reduce water recycling activities.

Q. DO YOU BELIEVE IT IS POSSIBLE TO RETAIN A VIABLE WAY OF RECYCLING PRODUCED WATER WITH AN ABSOLUTE CUTOFF IN THE 2 TO 5 TPY RANGE AS PROPOSED IN THE RULE?

A. Based on my review of research related to the topic, it appears that recycling operations would need to be reduced in size to meet the emissions limit. Because the economics of recycling produced water are already challenged, and there are economies of scale and risk reduction associated with larger facilities, this would make some projects infeasible.

Q. WHAT SHOULD BE DONE INSTEAD TO ENCOURAGE RECYCLING OF PRODUCED WATER WHILE STILL ENSURING APPROPRIATE EMISSIONS CONTROLS?

A. I believe additional research related to emissions from recycling operations is necessary to better predict the outcome of the proposed rule.

By: /s/ Ken Nichols
Ken Nichols

Appendix A6 – Direct Testimony of John Dunham

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION
20.2.50 **No. EIB 21-27 (R)**
Oil and Gas Sector – Ozone Precursor Pollutants

TESTIMONY OF JOHN DUNHAM

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1. What is your name, professional affiliation and educational background?

John Rowland Dunham, I am managing partner of John Dunham & Associates (aka Guerrilla Economics) a policy economics consulting firm. I have a BA from the University of Colorado, an MA in economics from the New School for Social Research, and an MBA from Columbia University

2. Can you give a brief summary of your expertise in evaluating economic impacts affecting the oil and gas industry?

I was an economic consultant to Western Energy Alliance for 7 years and conducted the industry economic impact study during that period. I also performed about 10 regulatory impact studies for the organization during that time.

I have also consulted for Anadarko petroleum, Americas Natural Gas Alliance, and the US Oil & Gas Association on various issues related to oil and natural gas regulations

3. Can you briefly summarize the model that you used?

In essence the model is a micro economic model of the oil and natural gas industry in New Mexico. Average production facility costs are based on data from the Input/Output model of the United States as prepared by IMPLAN Inc. The model tells me what it costs (and what is used) to produce each $1 of oil and natural gas in the state. This model is based on data from 2018, however, prices and the number of facilities (wells) was updated to 2020 data.

The model is designed to be "shocked" with different assumptions on changes in costs and revenues. Based on these changes the model re-giggers itself to a new equilibrium. This equilibrium is based on what we call a gravity model. Basically, the model either opens up new facilities, or closes existing facilities in order to bring the overall margin on oil and natural gas produced in the state back to where it was prior to the shock.

In this case, it starts to shut down facilities starting with the least productive first, until such point where the model rebalances.

4. In preparing your analysis, did you look at a particular document to understand the rule proposed by NMED? If so, what was it?

Environmental Protection, Air Quality (Statewide), Oil and Gas Sector – Ozone Precursor Pollutants, Proposed Rule, New Mexico Environmental Improvement Board, May 6, 2021.

5. Based on this analysis, what were your conclusions?

That the rule would cost oil and natural gas producers in the state a minimum of $3.8 billion 2020 dollars in direct administrative and operational costs over a 5 year period, with the bulk of these costs occurring in the first year or two

6. In Table 4 of your report, you provided an "Average Estimated Production and Revenues by Well Type"? Is this the gross or net revenue?

Gross

7. What must come out of the gross revenue to determine the net revenue for the operator?

In general, the cost of goods sold (or cogs). Depending on the company these would include leasing costs, production costs, taxes and royalty payments, and potentially gathering and processing costs.

8. Do operators maintain wells that will only break even on a net basis or do they typically demand some return over and above break even?

At current gas prices that are already a large number of older wells that are operating at a loss on a net basis. However, companies will generally keep facilities operating if they are able to cover their fixed costs, in particular in this industry since the cost of shutting in wells can be high.

9. Based upon these considerations, what percent of the oil wells and what percent of the gas wells may be at risk of shut down and plugging?

Based on the estimated cost of the rule about 37.2 percent of the currently operating (primary) oil wells, and as many as 87.0 percent of the natural gas wells, would become unproductive in that they would lose money due to the cost of the retrofits. While some would continue to operate because they would still cover fixed costs, it must be remembered that most of the costs imposed by the rule would be considered fixed costs.

10. What happens to the royalties paid to the landowner or mineral rights owner if a well is plugged and abandoned?

I did not cover royalties

11. Do you have an estimate of the amount of reduced royalty payments to New Mexicans that may result from the proposed rule?

I did not cover royalties

12. If a well is shut down and plugged, does it still require employees to service it?

On occasion, there would still be remediation and monitoring costs for plugged wells.

13. Do you have an estimate of the number of employees who may lose their jobs as a result of the proposed rule?

My estimate is that about 1,200 full-time equivalent jobs would be lost in the industry itself, along with about 2,000 FTE jobs in supporting industries. These are FTE jobs so they are made up of full jobs plus also bits and pieces of other jobs. So for example, the petroleum engineer in charge of a whole play may not lose their job, however, they may see hours reduced.

14. Do many of these jobs pay better than the mean and median incomes in New Mexico?

According to the BLS (2020 data), the average (or mean) wage in New Mexico is $49,650, while the median (or middle) wage is $37,378. Our analysis suggests that the average wage for the jobs lost is $76,691 for the industry jobs, and $55,735 for all jobs. This is a 2018 wage as the model we are using was last updated in 2018.

I have no way to calculate a median wage using the input/output data.

By: /s/ John Dunham
John Dunham

MEMORANDUM

TO:	New Mexico Oil & Gas Association
FROM:	John Dunham, Managing Partner
DATE:	June 13, 2021
RE:	Estimated Costs of Proposed Ozone Precursor Rule on Oil and Natural Gas Development in New Mexico

The New Mexico Environment Department is proposing a regulation for adoption by the New Mexico Environmental Improvement Board that will impact the development of the petroleum industry in New Mexico, by requiring new standards and monitoring of certain production facilities in the state.[1]

The following is an updated examination of the potential cost of this new rule on oil and natural gas producers in New Mexico, along with an economic impact analysis of the effects of these costs.[2] The analysis is being done using a model developed for the Western Energy Alliance by John Dunham & Associates in 2018, updated to reflect current well counts and petroleum prices in the state of New Mexico.

Summary

Based on data gathered from operators in New Mexico, the state and federal governments, and a model developed for the Western Energy Alliance in 2018, the proposed rule enacted in New Mexico would cost operators as much as $3.2 billion to comply with in the first year, and a discounted $3.8 billion over the course of 5 years.

Table 1
Summary of Costs to the Oil and Natural Gas Industry in New Mexico Resulting from Proposed Ozone Precursor Rule

	Proposed Rule
Administrative Costs	$ 352,565
Operational Costs	$ 3,248,759,403
Total Costs	$ 3,249,111,968
5-Year Costs	$ 3,852,291,118
NPV 5-Year Costs	$ 3,830,083,361

The increased costs would force operators to shut down marginal wells and forfeit the development of new plays in the state. This could lead to a loss of as many as 3,217 jobs in the petroleum production industry in New Mexico and cost the state's economy $674.2 million annually. In addition, the state and its localities would receive almost $22.9 million less in tax revenue from businesses and employees in the oil and gas industry. This does not include reduced royalty and severance tax revenues resulting from lower production.

Table 2

1 *Environmental Protection, Air Quality (Statewide), Oil and Gas Sector – Ozone Precursor Pollutants,* Proposed Rule, New Mexico Environmental Improvement Board, May 6, 2021.

2 An earlier analysis was conducted by John Dunham & Associates in September of 2020.

Economic Cost of the Proposed Ozone Precursor Rule on New Mexico's Economy

	Jobs	Wages	Economic Output
Direct	(1,207)	$ (108,284,469)	$ (358,590,607)
Supplier	(623)	$ (39,377,218)	$ (119,562,267)
Induced	(1,387)	$ (62,141,272)	$ (196,006,679)
Total	(3,217)	$ (209,802,960)	$ (674,159,553)

State and Local Business and Personal Taxes	$ (22,862,830)

The Model

In order to determine the economic impact of the new ozone precursor rule on the oil and natural gas industry in New Mexico, it is necessary to determine exactly how it would impact overall costs. As costs for developing projects rise, the number undertaken will fall. The key is to determine how the restrictions will impact:

1. Direct costs: For example, costs related to additional equipment;
2. Financial costs: Or those related to the cost of money resulting from increased delays;
3. Input prices: Higher costs for equipment and crews resulting from increased demand;
4. Revenues: Reduced revenues resulting from both wells not drilled and delays in well servicing.

These additional costs are run through the oil and natural gas well model developed for Western Energy Alliance by John Dunham & Associates (JDA) in 2018. The model was updated to reflect the current number of operating oil and natural gas wells in New Mexico,[3] as well as current average prices for oil at the wellhead in New Mexico, and the citygate price for natural gas in the state.[4]

These figures are linked to the economic impact model and from that an estimate of lost jobs, economic activity and taxes are developed.[5]

The Western Energy Alliance model is based on a wide range of data sources and assumptions, each of which impacts the final results. JDA has striven to ensure that the assumptions are as cautious as possible leading to what is likely a low estimate of the overall cost of the proposed rule. Each of these assumptions, along with the data used in the development of the models, is detailed below:

<u>Average Drilling Costs</u> are estimated based on data derived from the US Department of Commerce, Bureau of Economic Analysis by IMPLAN Inc. in 2016. These data come from the Input/Output accounts of the United States. These data present detailed figures on the input costs for oil and gas well drilling including wages, capital costs, leasing costs, and costs of various materials and services used in the drilling and completion of oil and gas wells. The data are from 2016. The figures used in this model are based on the average cost per dollar of output (basically sales) multiplied by the estimated sale of oil and natural gas in each state as of 2020. Annual average prices and production volumes by state are gathered from the US Department of

3 *OCD Well Statistics*, State of New Mexico, Oil Conservation Division, January 28, 2021 at: http://www.emnrd.state.nm.us/OCD/statistics.html.
4 Wellhead price data are not available.
5 Western Oil & Natural Gas Employs America, John Dunham & Associates for Western Energy Alliance, 2018.

Energy.[6] Costs are divided between exploration/leasing/permitting, drilling and completion, with the distribution between these two processes based on the type of input and labor costs. About 52.4 percent of the drilling/completion cost is assumed to be for drilling and the rest for completion.[7]

Production Costs are estimated based on data derived from the US Department of Commerce, Bureau of Economic Analysis by in 2016. These data come from the Input/Output accounts of the United States. These data present detailed figures on the input costs for oil and gas production including wages, capital costs, leasing costs, and costs of various materials and services used in the exploration/leasing/permitting, production, infrastructure development and reclamation of oil and gas plays. The data are from 2016. The figures used in this model are based on the average cost per dollar of output (basically sales) multiplied by the estimated sale of oil and natural gas using the latest data available. Annual average prices and production volumes by state are gathered from the US Department of Energy.[8] Costs are divided between different activities based on the type of input and labor costs are divided based on input commodity and service costs.

Anticipated Revenues are based on data from the US Department of Energy. It is simply equal to the annualized price of either oil or natural gas at the wellhead (by state), multiplied by annual production.[9] Revenues per well cannot be derived simply by dividing this by the number of producing wells since oil and gas wells tend to have either a hyperbolic or an exponentially declining production trend. Based on discussions with industry principals, a well will generally not be drilled and put into production unless it can recoup at least the direct drilling costs in the first year after completion. Using this assumption and a simple declining exponential function, the model suggests that about 97 percent of the production occurs in the first 4 years after drilling. The four-year production total (multiplied by the current price of either oil or gas) was used to estimate total revenue per well. Operating costs were then multiplied by 4 to reflect the economic life of each well.

The Number of Wells To Be Drilled is estimated based on data from individual state permitting authorities. Each authority uses different methods to identify whether wells are gas or oil (or both) and the wells' stage in the production process. While complete standardization between the states is not possible, in general it is possible to label a well as oil or gas, or as being in some stage of pre-production.

The Number of Producing Wells is also estimated based on data from individual state permitting authorities. Again, each authority uses different methods to identify whether wells are gas or oil (or both) and the wells' stage of production. While complete standardization between the states is not possible, in general it is possible to label a well as oil or gas, and that it is in some stage of production. Water wells, disposal wells, capped wells, injection wells, and other operations not directly used to extract petroleum are not included.

6 See *Domestic Crude Oil First Purchase Prices by Area*, US Department of Energy, Energy Information Administration, at: www.eia.gov/dnav/pet/pet_pri_dfp1_k_a.htm
7 The model is based on average costs and revenues. These can vary greatly by play, product and individual well.
8 Op cit. *Domestic Crude Oil First Purchase Prices by Area*
9 Ibid.

Table 3 below outlines the number of oil and natural gas wells used in the model, as well as the estimated production and prices.

Table 3
Annual Production Statistics and Assumptions for New Mexico (2020 Data)

	Oil	Natural Gas	Total
Number of Wells			
High Production	34	219	253
Medium Production	7,089	17,550	24,639
Low Production	26,170	33,185	59,355
Total Wells	33,293	50,954	84,247
Production	**Barrels**	**Million (Cu Ft)**	
High Production	12,825,551	227,148.7	
Medium Production	262,880,023	1,473,358.6	
Low Production	103,403,426	349,916.6	
Total Production	379,109,000	2,050,424.0	
Prices	$56.14	$2,856.67	
Revenue	$21,281,915,563	$5,857,377,893	$27,139,293,457

On a per well basis, the data suggest (Table 4) that the vast majority of oil and natural gas wells generate very little in the way of revenue, and the potential costs of the rules under consideration would be so high as to encourage operators to simply cap the wells rather than continue to produce.[10]

Table 4
Average Estimated Production and Revenues by Well Type

	Oil		Natural Gas	
Average Production Per Well	Barrels (Annual)	Barrels Per Day	Million Cu Ft (Annual)	MCF Per Day
High Production	377,931	1,035	1,035	2,835
Medium Production	37,081	102	84	230
Low Production	3,951	11	11	29
Average Revenue Per Well	Annual	Per Day	Annual	Per Day
High Production	$21,215,767	$58,125	$2,956,499	$8,100
Medium Production	$2,081,590	$5,703	$239,818	$657
Low Production	$221,811	$608	$30,122	$83

Note that this does not include condensate produced in what are essentially natural gas wells as this is a very low number in the natural gas plays in New Mexico

As the analysis below will show, as wells become uneconomical due to higher regulatory costs, production slows and jobs in the industry are eliminated. Based on a model developed for Western Energy Alliance in 2018, the oil and natural gas industry is a major part of the New Mexico economy, directly employing nearly 7,740 FTE people, and creating a total of almost

10 Based on data originally developed for Western Energy Alliance, 2018. These data represent production figures across most of the western part of the country. A high production oil well is considered to be one producing over 400 barrel of oil equivalent (BOE) per day, a low production well is considered to be one producing between 1 and 15 BOE per day. Data taken from *Distribution and Production of Oil and Gas Wells by State*, EIA website: http://www.eia.gov/pub/oil_gas/petrosystem/petrosysog.html. Data retrieved 05/06/2014

25,820 FTE jobs.[11] All told, the industry generated almost $6.9 billion in economic activity in the state in 2018, and firms and their employees paid state and local governments $233.4 million in taxes.[12]

Table 5
Economic Impact of Oil and Natural Gas Industry in New Mexico (2018 Baseline)

	Jobs	Wages	Economic Output
Direct	7,737	$ 751,669,030	$ 3,978,310,389
Supplier	6,917	$ 436,862,521	$ 1,326,459,201
Induced	11,165	$ 500,176,207	$ 1,577,661,247
Total	25,818	$ 1,688,707,759	$ 6,882,430,838
State and Local Business and Personal Taxes			$ 233,404,461

Ozone Precursor Rule

The New Mexico Environmental Improvement Board is contemplating issuing rules restricting the emission of volatile organic compounds (VOCs) and nitrogen oxides (NOx) from sources located within counties that have areas with ambient ozone concentrations in excess of ninety-five percent of the national ambient air quality standard for ozone, including but not limited to Chaves, Eddy, Lea, Rio Arriba, Sandoval, and San Juan counties. Wells located in Bernalillo County, on Tribal Lands, and in other areas that are not within the Board's jurisdiction are expected to be excluded from the rules. These rules would impact roughly 97.3 percent of the existing oil and natural gas wells in New Mexico, with the remaining facilities operating in parts of the state that are excluded from the requirements.

Based on a reading of the rule's language, oil and natural gas producers would be impacted by a wide range of requirements. According to the language in the document, there would be a minimum of 35 new administrative requirements that will need to be adhered to, as many as 16 provisions that will require additional equipment to be installed and maintained, and 46 provisions that will lead to new operational costs.[13]

These rules would impact the operation and maintenance of about 81,975 oil and natural gas wells in New Mexico and would lead to a reduction of further development in the state.

Costs Associated With The Proposed Rule

Administrative Costs

The proposed ozone precursor rule implies that oil and natural gas producers in the state will be required to abide by approximately 35 new administrative requirements. Each of these will require that operators dedicate staff time that could otherwise be directed toward more productive activities. In its Regulatory Impact Analysis of similar rules conducted in 2015, the US Environmental Protection Agency (EPA) stated that recordkeeping and reporting

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11 See: Western Oil & Natural Gas Employs America, prepared by John Dunham & Associates for Western Energy Alliance, 2018, https://legacy.westernenergyalliance.org/employsamerica

12 Not including taxes and royalties on oil and natural gas production.

13 *Environmental Protection, Air Quality (Statewide), Oil and Gas Sector – Ozone Precursor Pollutants,* Proposed Rule, New Mexico Environmental Improvement Board, May 6, 2021.

requirements would equate to 92,658 labor hours for 2,552 facility owners and operators.[14] There is no source for where these data came from. This works out to an average of 36.30 hours per company.

> **Database Management Systems**
>
> Database Management Systems (DBMS) can be extremely expensive. Licenses for database software alone can range upwards of $5,000 to $10,000 per month, not including the custom software needed for data entry and reporting.
>
> Off the shelf well management software can cost $600 per year per well, so a company with 100 wells would be paying $60,000 per year just for the software.
>
> And these costs do not include the IT staff necessary to manage the system. In New Mexico, a database administrator has an annual average wage of $78,270, not including benefits. So even a small company would be paying a minimum of about $150,000 per year just to maintain the required databases. The cost for larger firms would be in the millions of dollars annually.

Since this rule would apply only to wells being operated in specific parts of the state, the requirement should be adjusted to account for those operations that are in other areas. Based on wells operating in New Mexico in 2020, 97.3 percent of the operations would be covered by the rule, reducing the administrative requirement to 35.30 hours per firm.[15]

While these estimates are based on similar rules regarding the release of certain waste gases, those proposed rules did not include all of the databases, and data management software that would be required by the New Mexico Environment Department. The systems being envisioned by the proposed rules do not even exist, making it nearly impossible to estimate their costs. As such, the administrative costs estimated here are likely millions of dollars too low. Considering that 194 individual firms will be required to develop, or purchase, a database system that not only maintains records, but allows for remote access, this might actually be the most expensive part of the rule.

The analysis below uses wage rates from the Bureau of Labor Statistics for May of 2020.[16] A mathematical median wage per hour for the occupations identified below is used. The median wage is multiplied by 1.117 to account for social insurance taxes, benefits, unemployment insurance and other labor costs assumed by the employer.

Table 6
Wage Rates Used in Analysis of Administrative Expenses (Annual)

Occupation	Median Wage	Adjusted All-in Median Wage
Accountants and Auditors	$ 61,298	$ 89,010
Engineers, All Other	$ 121,950	$ 177,084
Lawyers	$ 90,293	$ 131,114
Bookkeeping, Accounting, and Auditing Clerks	$ 38,106	$ 55,333
Information and Record Clerks, All Other	$ 43,534	$ 63,216
Legal Secretaries and Administrative Assistants	$ 41,891	$ 60,830
Average		$ 96,098
Hourly		$ 46.20

Annual wages have been calculated by multiplying the corresponding hourly wage by 2,080 hours.

14 *Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector,* U.S. Environmental Protection Agency, Office of Air and Radiation and Office of Air Quality Planning and Standards, August 2015.

15 This would be the same calculation as reducing the number of firms by 2.5 percent.

16 May 2020 State Occupational Employment and Wage Estimates: New Mexico. These are the latest data currently available.

According to data from the Bureau of Labor Statistics, there are 194 establishments involved in the production of oil and natural gas in New Mexico.[17] Assuming a similar administrative burden as the federal rule would mean that companies would spend over 6,852 hours to comply. At a wage rate of $46.20, this equals $316,565 in administrative costs per year.

Equipment and Operational Costs

Using data from a survey of members conducted by the New Mexico Oil and Gas Association it is possible to calculate the equipment and operational costs that would be imposed by the new rule on a per well basis.[18] The new rule will place significant burdens on operators, both initially as wells are drilled and completed, and then over time, as operators are required to maintain systems and change their operational behaviors. The initial costs would be over $3.2 billion and will consist mainly of new construction and equipment requirements as wells are drilled, and equipment requirements as old wells are retrofitted.

Table 7
Additional Operational Costs Associated With Proposed Ozone Precursor Rules

	Per Oil Well	Per Natural Gas Well	Oil Production Costs	Natural Gas Production Costs	Total Costs
RFID Tag	$ 281	$ 281	$ 9,102,739	$ 13,931,759	$ 23,034,498
Engines	$ 1,336	$ 1,336	$ 43,265,576	$ 66,218,047	$ 109,483,624
Compressors	$ 55	$ 55	$ 1,787,690	$ 2,736,064	$ 4,523,754
Open Flares	$ 3,076	$ 3,076	$ 99,642,977	$ 152,503,766	$ 252,146,743
Enclosed Combustion Devices (ECD) and Thermal Oxidizers (TO)	$ 9,681	$ 9,681	$ 313,612,225	$ 479,984,109	$ 793,596,334
Vapor Recovery Units	$ 5,866	$ 5,866	$ 190,036,547	$ 290,851,297	$ 480,887,844
Gas Well liquid Unloading	$ -	$ 2,813	$ -	$ 139,441,542	$ 139,441,542
Glycol Dehydrators	$ 9,681	$ 9,681	$ 313,612,225	$ 479,984,109	$ 793,596,334
Heaters	$ 86	$ 86	$ 2,790,777	$ 4,271,290	$ 7,062,067
Hydrocarbon Liquid Transfers	$ 2,813	$ -	$ 91,108,375	$ -	$ 91,108,375
Pipeline Pig Launching and Receiving	$ 2,813	$ 2,813	$ 91,108,375	$ 139,441,542	$ 230,549,918
Pneumatic Controllers and Pumps	$ 1,689	$ 1,689	$ 54,727,221	$ 83,760,116	$ 138,487,337
Storage Tanks	$ 5,706	$ -	$ 184,841,033	$ -	$ 184,841,033
Total	$ 43,083	$ 37,377	$ 1,395,635,762	$ 1,853,123,641	$ 3,248,759,403

In sum, the operational and administrative costs of the potential rules could equal as much as $3.2 billion dollars in the first year, although they would fall significantly from then on.

NPV calculation

The costs of the new rule will not be one-time effects but will continue year after year. The bulk of the continuing costs would be administrative, however, there will be additional operational costs as well. Based on discussions with operators in New Mexico, JDA estimates that about 15.2 percent of the costs will continue each year, declining over time as wells are naturally removed from service. Over a 5-year period, assuming 3 percent inflation, the costs will equate to about $3.85 billion. Discounting this back to 2020 dollars using a discount rate of 3.23 percent,[19] the net present value of the stream of costs would be roughly $3.83 billion. See Table 8 on the following page.)

17 *Quarterly Census of Employment and Wages*, US Department of Labor, Bureau of Labor Statistics, at: https://www.bls.gov/cew/data.htm.

18 Survey data represents reporting by 10 companies.

19 *ICE BofA US High Yield Index Option-Adjusted Spread*, Ice Data Indices, LLC, retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/BAMLH0A0HYM2, June 10, 2021.

Table 8
Net Present Value of Costs Associated With Proposed Rules

	Proposed Rule
Administrative Costs	$ 352,565
Operational Costs	$ 3,248,759,403
Total Costs	$ 3,249,111,968
5-Year Costs	$ 3,852,291,118
NPV 5-Year Costs	$ 3,830,083,361

Economic Impact of Proposed Ozone Precursor Rule

Based on the Western Energy Model, if the costs outlined above are reflective of the entire industry in the state of New Mexico, the results could be devastating for the oil and natural gas sector of the economy. Were these costs to be incurred, it would be likely that 37.2 percent of the currently operating oil wells, and as many as 87.0 percent of the natural gas wells, would become unproductive in that they would lose money once the cost of the retrofits is put in place. These would predominately be the lower- and mid-range producing wells, so overall there would be a roughly 12.9 percent reduction in oil production and a 22.8 percent reduction in natural gas production.[20] Overall, there would be a 15.0 percent reduction in output of both oil and natural gas in terms of value.

New Mexico Natural Gas Production

While it might seem as if the model is overestimating the impact of the proposed regulation on natural gas production in the state, it is important to remember that over 50 percent of the producing (primary) natural gas wells in New Mexico account for just under 10 percent of production. On average, these wells produce roughly 23.5 MCF per day of natural gas, generating about $21,500 per year in revenues.

Based on the analysis, the average first year operational cost of complying with the proposed rule would be nearly $37,300. This means that all of the revenue produced by one of these wells over a 21-month period would go toward just the operational costs of compliance. Under these conditions, operators would be forced to cease production.

These low production wells tend to be located in older fields in and around the San Juan basin, located in the counties of San Juan, Rio Arriba, McKinley and Sandoval.

As this impact passes through the economic system in New Mexico, it will surely lead to reductions in jobs. Looking at the baseline, there were about 25,820 jobs in the oil and natural gas industry in the state. The reduction would likely lead to 1,207 lost jobs directly in the oil and natural gas industry in the state, and a total of 3,217 lost jobs. The state economy would face a $674.2 million loss, and state and local taxes would fall by nearly $22.9 million (See Table 9 on the following page).

Changes From Prior Analysis

In September of 2020, John Dunham & Associates examined two regulations then being promulgated by the state of New Mexico. Those rules included one establishing emissions standards for volatile organic compounds and nitrogen oxides for oil and gas production and processing sources located in certain areas of the state, while the second would require the capture of up to 98 percent of all natural gas produced in the state. This second rule has been

[20] Note that with the current slump in natural gas prices many of the existing natural gas wells are barely productive already.

adopted with some changes by the Oil Conservation Commission,[21] while the first rule is substantially similar to the one being proposed by the Environmental Improvement Board.

Table 9
Economic Cost From Proposed Ozone Precursor Rule on the Oil and Natural Gas Industry in New Mexico

	Jobs	Wages	Economic Output
Direct	(1,207)	$ (108,284,469)	$ (358,590,607)
Supplier	(623)	$ (39,377,218)	$ (119,562,267)
Induced	(1,387)	$ (62,141,272)	$ (196,006,679)
Total	(3,217)	$ (209,802,960)	$ (674,159,553)
State and Local Business and Personal Taxes			$ (22,862,830)

The earlier analysis was based on the same methodology and modeling as the examination presented in this paper; however, the number of active wells, production levels per well, and oil and natural gas prices were different than today. The new analysis includes more oil and natural gas wells (an increase of 2.1 percent), and significantly more production per well. In addition to this, prices are higher, meaning that each production facility lost due to higher costs will have a greater economic impact.

Table 10
Change in Base Data from Prior Analysis

	2020 Analysis			2021 Analysis			Pct Change		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Number of Wells	31,584	50,955	82,539	33,293	50,955	84,248	5.4%	0.0%	2.1%
Total Production	330,901,700	1,819,534		379,109,000	2,050,424		14.6%	12.7%	
Prices	$53.01	$2.74		$56.14	$2.86		5.9%	4.3%	
Revenue	$17,541,099,117	$4,985,523,160	$22,526,622,277	$21,281,915,563	$5,857,377,893	$27,139,293,457	21.3%	17.5%	20.5%

In addition, the estimated administrative costs of the rule have risen based not only on higher wages in New Mexico, but also because the proposed rule imposes more administrative requirements. Overall, the Net Present Value over 5 years of the proposed ozone precursor rule is down by about 2.0 percent from the earlier analysis mainly because that analysis also included a waste gas rule which was subsequently implemented by the state Oil Conservation Commission. (See Table 11)

Table 11
Change in Estimated Cost of the Proposed Rule from the Prior Proposed Rule

	2020	2021	Pct Change
Administrative Costs	$ 273,420	$ 352,565	28.9%
Operational Costs	$ 3,332,307,587	$ 3,248,759,403	-2.5%
Total Costs	$ 3,332,581,007	$ 3,249,111,968	-2.5%
5-Year Costs	$ 3,944,160,332	$ 3,852,291,118	-2.3%
NPV 5-Year Costs	$ 3,909,019,063	$ 3,830,083,361	-2.0%

21 *Natural Resources and Wildlife, Oil and Gas, Venting and Flaring of Natural Gas*, New Mexico Code, Title 19, Chapter 15, Part 27.

In the September 2020 model, it was estimated that 257 jobs would be lost versus 3,217 in this update. This is because a different modeling technique was used in this report that takes into account both losses of the number of facilities (wells) in the state, as well as the financial losses resulting from the proposed rule.

Table 12
Comparison of Economic Impact from 2020 to 2021 Analysis (Proposed VOC Rule Only)

2021	Jobs	Wages	Economic Output
Direct	(1,207)	$ (108,284,469)	$ (358,590,607)
Supplier	(623)	$ (39,377,218)	$ (119,562,267)
Induced	(1,387)	$ (62,141,272)	$ (196,006,679)
Total	(3,217)	$ (209,802,960)	$ (674,159,553)
State and Local Business and Personal Taxes			$ (22,862,830)

2020	Jobs	Wages	Economic Output
Direct	(93)	$ (8,857,892)	$ (29,186,594)
Supplier	(51)	$ (3,205,011)	$ (9,731,474)
Induced	(113)	$ (5,076,497)	$ (16,012,343)
Total	(257)	$ (17,139,401)	$ (54,930,410)
State and Local Business and Personal Taxes			$ (1,862,860)

In sum, the estimates of the cost and economic losses resulting from the proposed emissions rule are much larger now than they were previously estimated to be. This is a result of continued development of the oil and natural gas sector in New Mexico since last year, and due to higher wellhead prices for both oil and natural gas.

About John Dunham & Associates:

John Dunham & Associates (JDA) is a leading New York City based economic consulting firm specializing in the economics of fast-moving issues. JDA is an expert at translating complex economic concepts into clear, easily understandable messages that can be transmitted to any audience. Our company's clients have included a wide variety of businesses and organizations, including some of the largest Fortune 500 companies in America, such as:

- Altria
- Diageo
- Feld Entertainment
- Forbes Media
- MillerCoors
- Verizon
- Wegmans Stores

John Dunham is a professional economist with over 30 years of experience. He holds a Master of Arts degree in Economics from the New School for Social Research as well as a Masters of Business Administration from Columbia University. He also has a professional certificate in Logistics from New York University. Mr. Dunham has worked as a manager and an analyst in both the public and private sectors. He has experience in conducting cost-benefit modeling, industry analysis, transportation analysis, economic research, and tax and fiscal analysis. As the Chief Domestic Economist for Philip Morris, he developed tax analysis programs, increased cost-center productivity, and created economic research operations. He has presented testimony on economic and technical issues in federal court and before federal and state agencies.

Prior to Phillip Morris John was an economist with the Port Authority of New York and New Jersey as well as for the City of New York.

Appendix B – Redlines

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 Part~~rule or anytime thereafter~~, have ~~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 12 becomes subject to this rule, the requirements of the rule are irrevocably effective unless the source obtains a 13 federally enforceable air permit limiting the potential to emit to below such applicability thresholds established in 14 this Part.~~ As of the effective date, sources located in the following counties of the state are subject to this Part: Dona Ana, Eddy, Lea, Sandoval, San Juan, and Valencia.

A. If, at any time after the effective date, any area in the state is determined by the department to have exceeded 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, the department shall revise this rule to incorporate such areas consistent with Sections 74-1-9 and 74-2-6 NMSA. The notice of proposed rulemaking shall be published no less than one hundred and eighty (180) days before the sources in the affected area will become subject to this Part and shall include the monitoring ~~, testing, or inspection~~ data, and all other technical information, that demonstrate that the area or areas ~~the~~ subject ~~of~~ to the proposed rulemaking exceed ninety-five percent of the national ambient air quality standard for ozone.

(1) The proposed rule revision shall include, in addition to the requirements of 20.1.1.301.B. NMAC:

(a) a list of the areas that the board proposes to become subject to this Part, and the date upon which the sources in the relevant area (or areas) will become subject to this Part; and

(b) proposed implementation dates, consistent with the time provided in the phased implementation schedules provided for in each Section of this Part, for sources within the area or areas ~~the~~ subject~~(s)~~ ~~of~~ to the proposed rulemaking to come into compliance with each Section of this Part.

B. Once a source becomes subject to this rule based upon potential to emit, any the requirements of the rule based upon potential to emit are irrevocably effective unless the source obtains a federally enforceable, or legally and practically enforceable limit on the potential to emit to below such applicability thresholds established in this Part, or the relevant section contains a threshold below which the requirements no longer apply.

[20.2.50.2 NMAC – N, XX/XX/2021]

Comment on 20.2.50.2: The schedules set forth in Section 50 afford sources a tiered schedule to address each subject unit. This redline addresses sources and areas that become subject to this Part after the effective date and provides a process for orderly inclusion of the newly affected sources and areas within the scope of the rule. This change is needed to provide assurance that sources will have sufficient notice and due process to incorporate changes. This revision also addresses the conditions under which a source may take enforceable limits to reduce emissions below the applicability thresholds of the standards and when sources must do so, including accounting for off-ramps contained within the regulations. This change is needed to provide clarity on how the applicability thresholds in the various standards should be interpreted.

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~~2022, 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 (NOx) for oil and gas production, processing, and natural gas 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 of ~~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.

Comment on 20.2.50.7(B): This change is needed because the open flare section includes use of auto ignitors. Open flares do not have a combustion chamber.

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.

Comment on 20.2.50.7(C): NMOGA requests that "intermittent" be removed from this definition to align with the federal and other state interpretations of "bleed rate," which exclusively refer to a continuous rate. See e.g., 40 C.F.R. 60.5430a (NSPS OOOOa). The bleed rate refers to the rate at which gas is consistently and continuously emitted to atmosphere or to a capture system between actuations. Intermittent controllers do not bleed continuously. Furthermore, both intermittent controllers and continuous bleed controllers actuate and release or vent emissions periodically. This is not the bleed rate and as proposed by NMED, this intermittent actuation could be inappropriately correlated with the bleed rate. To avoid inconsistency and confusion, NMED should similarly remove the term "intermittent bleed rate" from the recordkeeping requirement in 20.2.50.122(D)(5)(e). Further, pneumatic controllers operate on any pressurized gas (natural gas, air, nitrogen, etc.). This definition should be agnostic as to which gas is being used, and sections where this term is used should make it clear how those provisions apply depending on the gas being used.

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 minimal ~~no~~ loss of VOC emissions to the atmosphere.

Comment on 20.2.50.7(F): Change is required for technical feasibility purposes as there is no way to guarantee no loss of VOC emissions from closed vent system at all times.

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~~.

Comment on 20.2.50.7(G): Change is required to account for instances where a well is waiting on surface equipment or a gathering line to begin production. Especially considering the recently adopted regulations from the Oil Conservation Commission, first production may be delayed awaiting gas pipeline takeaway. This may be weeks or even months after the end of completion operations on wells associated with a Well Production Facility. Commencement of operation should not begin until production to sales occurs.

H. "Component" means a pump seal, flange, pressure relief device (including thief hatch or other 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, or installation ~~or relocation~~ of a stationary source, ~~including~~ but does not include ~~limited to~~ relocation, replacement in-kind, temporary installations, ~~and~~ or portable stationary sources.

Comment on 20.2.50.7(J): Defining "construction" to mean "relocation" would result in the frequent and unnecessary *prompting of new control requirements for portable stationary sources, which are specifically included in NMED's proposed definition. The proposed definition presents a particular concern for portable engines which are routinely relocated throughout a field. "Relocation" is incongruent with the terms "fabrication," "erection," or "installation," which are more associated with the introduction of a new stationary source at a location rather than the movement of an existing stationary source. The inclusion of "relocation" would be inconsistent with EPA's definition of "construction" under the NSPS and NESHAP regulations and NMED's definition of "construction" as used in the issuance of construction permits, none of which consider relocation to be construction. See 40 C.F.R. §§ 60.2, 63.2; 20.2.72.7 NMAC. Defining construction to include relocation may disincentivize operators from relocating oversized assets when well production declines. For example, an existing compressor may become oversized as well production decreases. Whereas an operator would normally change this unit out for a smaller, more appropriately sized compressor, operators may retain the larger and higher-emitting compressor to avoid triggering new standards. Portable engines are also regulated as nonroad engines, and states are generally preempted from regulating emissions from these units.*

K. **DELETED**~~**"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.~~

Comment on 20.2.50.7(K): Deletion requested as "Custody transfer" is only used in connection with "Local distribution custody transfer", a term that is defined separately at 20.2.50.7.K. Potential for future conflicting definitions.

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 control units (VRCUs), fuel cells, condensers, ~~air fuel ratio controllers (AFRs),~~ catalytic converters (oxidative, selective, and non-selective), or other equipment for the sole purpose of emission reduction~~ equipment~~. Devices that are only used during malfunctions, maintenance, upset or other temporary events are not considered control devices. A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department in an operating permit. ~~to comply with emission standards in this Part.~~

Comment on 20.2.50.7(L): Redline required to clarify the difference between vapor recovery units and vapor recovery control units. Vapor recovery units or towers can be utilized as process equipment or to control emissions from a process. EPA and NMED have long recognized this distinction and have employed a three-factor test to determine which VRUs are fairly regarded as a control device and subject to control device standards. See comment on 20.2.50.7(TT).
Redline required as an AFR does not thermally combust, chemically convert, or otherwise destroy or recover air contaminants and should not be considered a control device in the context of this rule. AFRs are considered process control devices, not control devices as per the screening process provided by EPA for vapor recovery units being considered "control" (paraphrased as follows):
Operator must answer the following three questions:
(1). Is the primary purpose of the equipment to control air pollution?
(2). Where the equipment is recovering product, how do the cost savings from the product recovery compare to the cost of the equipment?
(3). Would the equipment be installed if no air quality regulations were in place?

This redline also ensures that equipment must be used for the sole purpose of emission reductions before it is considered a control device. Oil and natural gas systems are complex, and often gases are routed to pilots and other combustion devices without being control devices. Further, NMOGA believes that it should be clarified that devices used during temporary events (maintenance, malfunction, etc.) should not be considered control devices and thus subject to the most rigorous requirements of devices used for more permanent events.

M. **"Department"** means the New Mexico environment department.

N. **"Downtime"** means the period of time when equipment is inoperable ~~not in operation, or when a well is producing, and the control device is not in operation.~~

Comment on 20.2.50.7(N): Redline is required for technical clarification. Just because something is not in operation doesn't mean it is out of service. For instance, a flare that is only used during pigging or loading operations. Similarly, there may be instances where a well is producing and a control device is not operating on location because that particular piece of equipment is not operating. For instance, a wellsite compressor may not be operating and hence the AFR and catalytic converter are not operating – but they are not needed for the well and other production equipment to operate properly.

O. “Enclosed combustion device” means a combustion device where waste ~~gaseous~~ gas ~~fuel~~ is combusted in an enclosed chamber solely for purpose of destruction. This may include, but is not limited to an enclosed flare or combustor., ~~, reboiler, and heater.~~

Comment on 20.2.50.7(O): Redline required to clarify that enclosed combustion devices should be regulated as control devices only where their purpose is to reduce emissions, as opposed to combustion devices used for purposes unrelated to emissions reduction (e.g., heaters or reboilers used to provide heat to a process).

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

Q. “Gathering and boosting ~~station~~site” means a permanent combination of equipment located downstream of a well production facility that: collects or moves ~~natural gas, crude oil, condensate~~natural gas prior to the inlet of a natural gas processing plant or prior to a natural gas transmission pipeline or transmission compressor station if no gas processing is performed; or collects, moves, or stabilizes crude oil or condensate prior to an oil transmission pipeline or other form of transportation. ~~, 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~~

Comment on 20.2.50.7(Q): Redline required to limit definitions to gathering and boosting stations and not transmission compression stations, which are covered below by new revised definition. Change from “station” to “site” is needed to align with other uses of the term throughout the rule. Change from wellhead site to well production facility required to clarify scope. Wellhead site implies only equipment at the wellhead pad, but not potentially centralized facilities remote from the wellhead pad servicing the production from that wellhead pad. Additional changes were required to clarify the end point on both the natural gas chain/line and the crude oil/condensate chain/line. See also definition of Well Production Facility, below.

R. “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.

S. “Hydrocarbon liquid” means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, and intermediate hydrocarbons. Hydrocarbon liquid does not include produced water.

Comment on 20.2.50.7(S): Addition is needed to clarify that produced water is not considered a “hydrocarbon liquid”. This is necessary because produced water may contain a very small amount of hydrocarbons. This change makes it clear that this rule does not treat produced water as a hydrocarbon liquid even when it contains a minor amount of hydrocarbons.
Redline required to align with other Parts requiring vapor capture during transfer of hydrocarbon liquid. Vapor capture for produced water storage is technically infeasible for sites utilizing VRCUs.

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

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

Comment on 20.2.50.7(U): Redline required to remove produced water because the only time the term “liquid transfer” is used in this part is in section 20.2.50.120, Hydrocarbon Liquid Transfers, and produced water is not a “hydrocarbon liquid” within the meaning of the rule. The removal of “or produced water” makes it clear that transfers of produced water are not included in that section. NMOGA does not believe it was NMED’s intent to include produced water within the scope of 20.2.50.120, nor does NMOGA believe inclusion would be appropriate. Relative to the unrefined petroleum liquids covered by section 20.2.50.120, produced water has low emissions potential and does not warrant the rigorous controls mandated. For example, requiring produced water trucks to meet vapor tightness standards that ordinarily apply only to gasoline cargo tanks (40 C.F.R. Part 63, Subpart R) would be a significant overreach, as vapor losses from gasoline vastly outweigh vapor losses from produced water. This would also be extremely disruptive: because produced water vehicles are generally not certified or designed to transport hazardous materials, NMED’s proposal would require a significant adjustment by the transportation industry and disrupt interstate commerce by imposing more stringent standards on transport than federal hazardous material law.

V. “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.

W. “~~Natural gas~~Transmission compressor station” means any permanent installation of one or more compressors that move ~~designed to compress~~ pipeline quality natural gas at increased pressure from production fields, ~~well pressure to gathering system pressure before the inlet of a~~ or natural gas processing plants, ~~or to move compressed natural gas~~ through a transmission pipeline for ultimate delivery to the local distribution company custody transfer station, into underground storage, or other industrial end users.

Comment on 20.2.50.7(W): Redline required to clarify that, when the term natural gas compressor station is used in the rule, it refers to transmission compressor stations. There are two types of compressor stations for purposes of the rule: those located at gathering and boosting sites and those used in transmission. In addition, compressors can be located at well production facilities. Those located at well production facilities are excluded from section 20.2.50.114 standards. Those located at gathering and boosting sites are already included in the term "gathering and boosting site," which includes permanent installations, such as compressor stations, downstream of production and upstream of the natural gas processing plant. The only other type of compressor station under the terms of the rule is transmission compressor stations, which are included in this revised definition.

X. **"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.

Y. **"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.

Z. **"New"** means constructed or reconstructed on or after the effective date of this Part.

AA. **"Non-Emitting Controller"** means a device that monitors a process parameter such as liquid level, pressure or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to: instrument air or inert gas pneumatic controllers, electric controllers, mechanical controllers and Routed Pneumatic Controllers.

Comment on 20.2.50.7(AA): This term is recommended to clarify what controllers are understood to be non-emitting as referenced in 20.2.50.122. All controllers that do not emit natural gas to the atmosphere under normal operations should be considered non-emitting for the purposes of this part.

BB. **"Operator"** means the person or persons responsible for the overall operation of a stationary source.

~~BB~~CC. **"Optical gas imaging (OGI)"** means an imaging technology that utilizes a high-sensitivity infrared camera designed for and capable of detecting hydrocarbons.

~~CC~~DD. **"Owner"** means the person or persons who owns a stationary source or part of a stationary source.

~~DD~~EE. **"Permanent pit or pond"** means a pit or pond used for collection, retention, or storage of produced water or brine and is installed for longer than one year.

Comment on 20.2.50.7(EE). Redline needed to align with revisions to 20.2.50.126.

~~EE~~FF. **"Pneumatic controller"** means a device that monitors a process parameter such as liquid level, pressure, or temperature and uses pressurized gas (which may be released to the atmosphere during normal operation) to send a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers.~~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.~~

i. "High-Bleed Pneumatic Controller" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of ~~natural~~ gas to the atmosphere.

ii. "Low-Bleed Pneumatic controller" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits less than or equal to 6 scfh of ~~natural~~ gas to the atmosphere.

iii. "Intermittent pneumatic controller" means a pneumatic controller that is not designed to have a continuous bleed rate, but is designed to only release ~~natural~~ gas above de minimis amounts to the atmosphere as part of the actuation cycle.

iv. "Routed Pneumatic Controller" means a pneumatic controller of any type that releases natural gas to a process, sales line or to a combustion device instead of directly to the atmosphere.

Comment on 20.2.50.7(FF): Redline proposed to provide better clarity and differentiate between a pneumatic controller and a control valve. Pneumatic devices are powered by pressurized gas, including natural gas, air, nitrogen, etc. This definition should be agnostic as to the gas being used, and section 20.2.50.122 Pneumatic Controllers and Pumps should be clear what regulations apply to various pneumatic devices based in part on what gases are used for actuation.

Comment on 20.2.50.7(FF)(i)-(iv): Redline required to provide clarification between controller types. NMOGA has proposed use of terms from Colorado's pneumatics rulemaking which has undergone significant discussion and engagement over the past several years. These definitions were agreed upon by environmental organizations, local governments, industry and the agency. NMOGA suggests NMED adopt specific definitions for the various types of pneumatic controller for clarity in the implementation of the proposed pneumatic controller facility-wide plan. These classifications/terms have been incorporated into the proposed redlines for ease of reference in the rule. These classifications correspond with how vendors sell these devices. Using these definitions will allow use of the vendor's classification for compliance purposes. NMOGA has also proposed a definition of "non-emitting pneumatic controller" to facilitate implementation of 20.2.50.122's phase out provisions.

~~FF~~GG. "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.

Comment on 20.2.50.7(GG): Pneumatic diaphragm pumps are driven by pressurized gas including natural gas, air, nitrogen, etc. This definition should be agnostic as to the particular gas being used, and section 20.2.50.122 Pneumatic Controllers and Pumps should be clear what regulations apply to various pneumatic devices based in part on what gases are used for actuation.

~~GG~~HH. "Potential to emit (PTE)" means the maximum capacity of a stationary source to emit an air ~~contaminant~~ pollutant under its physical and operational design. ~~The~~ Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and ~~a~~ restrictions 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 or legally and practically enforceable in an operating permit, authorization, or other requirement established under a federal, state, local or tribal authority. The PTE for nitrogen dioxide shall be based on total oxides of nitrogen.

Comment on 20.2.50.7(HH). Redline required to recognize all effective and enforceable means of reducing potential emissions that are available under New Mexico law. The prior definition only recognized limitations that are "federally enforceable" and did not clearly allow consideration of other legally and practically enforceable limitations. Including these broader concepts in the definition of PTE encourages consistency with other areas of New Mexico law where PTE is defined similarly. See, e.g., 20.2.79.120.B(2) NMAC (recognizing limitations enforceable as a practical matter). It is further important that operators can take into account state only permit requirements or other state only requirements in determining PTE

~~HH~~II. "Produced water" means a ~~fluid~~ liquid that is an incidental byproduct from ~~drilling for or~~ well completion and ~~the~~ production of oil and gas.

Comment on 20.2.50.7(II): Redline required for technical clarification. Produced water is produced during completions and production, not drilling operations. The Groundwater Protection Council provides the following definition of produced water, which is illustrative: "Produced water is defined as the water that exists in subsurface formations and is brought to the surface during oil and gas production. Water is generated from conventional oil and gas production, as well as the production of unconventional sources such as coal and bed methane, tight sands, and gas shale." https://www.gwpc.org/topics/produced-water.

~~II~~JJ. "Produced water management unit" means ~~a recycling facility or~~ a permanent pit or permanent pond 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 and associated equipment at that location used for the recycling of produced water~~.~~

Comment on 20.2.50.7(JJ): Redline required as recycling facilities do not align with PWMU requirements of this part. Oil and natural gas operations commonly extract saltwater from the earth as part of the production process. Operators can recycle the water, inject it back into working reservoirs for reuse, or discard it at a saltwater disposal site. When the waste reaches a saltwater disposal or recycle facility, it goes into steel tanks where the various byproducts are separated out. From there, the facility uses pumps to inject the water into underground porous rock formations sealed by impermeable strata. This clarifies that the scope of units/sources that are produced water management units is based primarily on those with large (greater than 50,000 barrel) permanent ponds/pits and also any associated equipment used for recycling.

~~**JJ**~~**KK.** **"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.

~~**KK**~~**LL.** **"Reciprocating compressor"** means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of a piston rod.

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

~~**MM.** **"Recycling facility"** means a stationary or portable facility used exclusively for the treatment, reuse, 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.~~

Comment on 20.2.50.7(MM): Redline required as the only use of "recycling facility" was deleted in definition of Produced Water Management Unit above, but equipment associated with permanent produced water ponds/pits was incorporated into that definition.

NN. **"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~~subject unit and either (a) the facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), or (b) the delegation of authority to such representative is approved in advance by the department.

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

Comment on 20.2.50.7(NN)(1): Redline required as NMED already has a definition of responsible official in Part 70. Redline makes definition the same to avoid confusion.

~~**OO.** **"Small business facility"** means, for the purposes of this Part, a source that is independently owned or operated by a company that is a 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.~~

Comment on 20.2.50.7(OO): Redline recommended as NMOGA has evaluated the Small Business Facility section and concluded that there is no operator in NM small enough to qualify.

OO. **"Stabilized"** when used to refer to stored condensate, means that the condensate has reached substantial equilibrium with the atmosphere and that any emissions that occur are those commonly referred to within the industry as "working and breathing losses"

Comment on 20.2.50.7(OO): Redline required to provide definition of stabilized, as storage vessels containing stabilized hydrocarbon liquid may be floating roof or other type of storage vessel and are not subject to requirements for closed vent systems similar to Colorado Regulation 7.

PP. **"Startup"** means the setting into operation of air pollution control equipment or process equipment.

QQ. **"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.

RR. **"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 or railcar, or a pressure vessel designed to operate in excess of 204.9 kilopascals (29.724 psi) without emissions to the atmosphere. A storage vessel does not include a storage vessel located at a saltwater disposal facility unless the storage vessel is associated with a produced water management unit.

Comment on 20.2.50.7(RR). Redline required to clarify that tanks at saltwater disposal facilities are not subject to the standard unless the vessel is associated with produced water management units. Tanks at saltwater disposal facilities that are not associated with produced water management units contain liquids consisting of water with insignificant amounts of stabilized skim oil that is not in vapor state at normal or elevated conditions, making regulation of such units unnecessary.

SS. "Tank battery" means a storage vessel or group of storage vessels that receive or store crude oil, condensate, or produced water from a well or wells for storage prior to shipment. This does not include storage vessels at saltwater disposal facilities unless associated with produced water management units.

Comment on 20.2.50.7(SS). Redline required to define tank battery, a term used throughout the rule but not defined. The definition also clarifies that tanks associated with saltwater disposal facilities are not subject to the standard unless the vessel is associated with produced water management units. Tanks at saltwater disposal facilities that are not associated with produced water management units contain liquids consisting of water with insignificant amounts of stabilized skim oil that is not in vapor state at normal or elevated conditions, making regulation of such units unnecessary. This definition also makes clear that tank batteries are those located within the production sector – i.e., those associated with and receiving liquids from wells in the production segment.

TT. "Vapor Recovery Control Unit" means a system composed of a scrubber, a compressor and a switch. Its main purpose is to recover vapors. The switch detects pressure variations and turns the compressor on and off. The vapors are drawn through a scrubber, where entrained liquids are captured and returned to the liquid pipeline system or to a storage vessel, and the vapor recovered is compressed into a sales pipeline or other process. To determine if this device is a vapor recovery unit (process) or a vapor recovery control unit (control) the operator must answer the following three questions:

(1). Is the primary purpose of the equipment to control air pollution?

(2). Where the equipment is recovering product, how do the cost savings from the product recovery compare to the cost of the equipment?

(3). Would the equipment be installed if no air quality regulations are in place?

If the primary purpose is to control air pollution then the device is a vapor recovery control unit. Such device's classification as a control or process unit in a final permit is binding upon both the Department and the operator.

Comment on 20.2.50.7(TT): Redline required as vapor recovery units may be process units or air pollution control equipment. Both EPA and NMED's Air Quality Bureau have recognized this "dual" role of vapor recovery units and have used the "three questions" test and economic analysis to determine how such units should be classified. This definition recognizes the historic tests used by EPA and NMED for when a vapor recovery unit is a piece of air pollution control equipment. Because of the complexity of the test, NMOGA believes that the status of vapor recovery units should be resolved in an appropriate permit proceeding, which would look at the facts and circumstances of each unit, and reach the most appropriate conclusion that would thereafter bind the operator.

UU~~SS~~. "Well workover" means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons.

~~UU~~VV. "~~Wellhead site~~Well Production Facility" means the equipment directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. A well~~head site~~ production facility may include equipment used for extraction, collection, routing, storage (e.g., tank battery), separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping.

Comment on 20.2.50.7(VV): Redline required because the "wellhead" site may not include any equipment, whereas well production facility is more encompassing of the requirements of this Part.

[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]

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 certain crude oil and natural gas production, and processing equipment ~~and~~associated with operations that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquids or produced water in the areas specified in 20.2.50.2 NMAC and are located at well production facility~~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. Part 50 applies only in areas of the State specified in 20.2.50.2 NMAC

B. In determining if any ~~source~~ unit 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 unit ~~source~~ as necessary. ~~and shall have the PTE calculation certified by a qualified professional engineer.~~ 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 refineries~~y~~ and oil transmission pipelines are not subject to this Part.
[20.2.50.111 NMAC - N, XX/XX/2021]

Comment on 20.2.50.111(B): Redline required to address two concerns. First, not all sections of this Part require calculation of PTE. Thus, we have included the term "as necessary" to reflect that not all applicability thresholds under this Part are based on PTE. Second, it is not appropriate to require a qualified professional engineer to complete the PTE calculation. Many companies have engineers, air quality specialists, or other staff that conduct these PTE analyses, and they may not meet the definition of a qualified engineer. This would require duplicative processes and may create significant concerns with the current qualifications of many of the individuals currently conducting these evaluations. There is no basis for requiring a certification by a qualified professional engineer. PTE is typically calculated based on reasonably accepted methodologies and does not require such a certification.
Furthermore, per the State of New Mexico Board of Licensure for Professional Engineers and Professional Surveyors, "An engineer employed by a business entity who performs only the engineering services involved in the operation of the business entity's business shall be exempt from the provisions of the Engineering and Surveying Practice Act; provided that neither the employee nor the business entity offers engineering services to the public" (Section 61-23-22 of the NM Engineering and Survey Practice Act). In other words, even the state licensing board for professional engineers in the State of New Mexico does not require a professional engineer complete this type of calculation.

20.2.50.112 GENERAL PROVISIONS:

A. General requirements:

(1) Units ~~Sources~~ subject to emissions standards and requirements under this Part shall be operated and maintained consistent with manufacturer specifications, or~~and~~ good ~~engineering~~ operational and maintenance practices, which terms, when used in this Part, mean the original equipment manufacturer (or successor) emissions-related design specifications, maintenance practices and schedules or an alternative set of specifications, maintenance practices and schedules . ~~The owner or operator shall keep manufacturer specifications and maintenance practices on file, which are being followed, and make them available upon request by the department. For sources~~ units ~~constructed prior to 1980 for which no manufacturer specifications and~~or ~~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 approved by qualified maintenance personnel based upon engineering principles and field experience.. The owner or operator shall keep such manufacturer specifications, or alternative specifications, ~~maintenance schedules~~ whichever are being followed, on file and make them available to the department upon request. The terms of this 20.2.50.112.A(1) NMAC apply any time reference to manufacturer specifications occurs in this Part.

Comment on 20.2.50.112(A)(1): Redline required as document changed to distinguish between "source" to "unit" throughout where appropriate. As written, the rule conflates stationary sources and sources (i.e., specific units subject to the rule). NMOGA proposes to use "source" when it refers to the stationary source or facility itself and "unit" when it refers to the specific affected/regulated equipment. In addition, with respect to the above, manufacturer specifications are not always appropriate for following either because (1) they are not developed or designed for the purposes of minimizing emissions, (2) owners and operators have developed their own specific practices for those sources, which should be deferred to; or (3) full compliance with manufacturer specifications simply encourages manufacturers to require more testing/maintenance (to the benefit of the manufacturing company).
Redline required as owners and operators may not have a complete set of manufacturer specifications, particularly for older equipment or equipment obtained during acquisitions. Additionally, original manufacturer specifications may not be relevant if the units are modified in the field or the original specifications are inadequate to maintain field reliability. Accordingly, the term "manufacturer specifications" should include similar specifications, maintenance practices and schedules developed by qualified personnel, when the original specifications are not available, not relevant due to modifications, or have been found inadequate or inappropriate based upon operator's experience. NMOGA agrees that these specifications should be available to the department upon request.

(2) Units ~~Sources~~, including associated air pollution control equipment and monitoring equipment, subject to emission standards or requirements under this Part shall at all times, including periods of startup, shutdown, and malfunction, be operated and maintained in a manner consistent with safety and good air pollution control practices for ~~to~~ minimizing~~e~~ emissions of ~~air contaminants, including~~ VOC and NOx. During a period of startup, shutdown, or malfunction, this general duty to minimize emissions requires that the owner or operator reduce emissions from the affected unit to the greatest extent which is consistent with safety and good air pollution control practices. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. The terms of this 20.2.50.112.A(2) apply any time reference to minimizing emissions occurs in this Part.

Comment on 20.2.50.112(A)(2): Redline required as NMOGA believes that the general duty clause is best located in the general provisions rather than appearing repetitively throughout the rule. NMOGA believes that NMED should follow the model established by EPA in the NESHAP program and adopted by reference by the EIB in 20.2.82.9 NMAC, which incorporates language from 40 CFR 63.6(e)(1)(i). NMOGA has cleaned the language up to eliminate some of the startup, shutdown and malfunction language which is currently in flux. The federal language, as cleaned up to minimize SSM conflicts, represents a good resolution of this issue that was reached after extensive notice and comment.

(3) Within two years of the effective date of this Part, owners and operators of a ~~source~~unit requiring ~~an~~ ~~E~~equipment ~~Monitoring~~ ~~monitoring~~monitoring, testing, or inspection ~~Tag (EMT)~~ will develop and implement database system(s) capable of storing information for each unit in a manner consistent with this section. ~~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 owner or operator shall maintain information regarding each unit requiring equipment ~~monitoring~~monitoring, testing, or inspection in a ~~database~~database system(s), including ~~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 (latitude and longitude) of the source at which the unit is located;
(c) type of ~~source~~ unit (e.g., tank, ~~VRU~~VRCU, 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;~~**(e~~f~~)** if available, make, model, and serial number; and
(f~~g~~) a link to the manufacturer's maintenance schedule or repair recommendations or company-specific ~~engineering~~operational and maintenance practices.

(4) The ~~database~~database system(s) ~~EMT~~ shall be ~~installed and~~ maintained by the owner or operator of the facility.

~~**(5)** The EMT shall be of a format scannable by an owner or operator's authorized required by this Part.~~

(5~~6~~) The owner or operator shall manage the ~~source's~~ unit's record of data in ~~a~~ the database system(s) and the ~~database~~database system(s) must be ~~that is~~ able to generate a Compliance Database Report (CDR). The CDR is an electronic report generated by the owner or operator's ~~database~~database system(s) and submitted to the department upon request. ~~The format of the CDR shall be determined by the department.~~

(~~7~~6) The CDR is a report distinct from the owner or operator's ~~database~~database system(s). The department does not require access to the owner or operator's database system(s), only the CDR.

(~~8~~7) ~~If read by the o~~Owner or operator's authorized representative must be able to access and input data in the ~~, the EMT shall access the owner or operator's database~~database system(s) record for that unit~~source~~. That access is not required to be at any time from any location.

(~~9~~8) The owner or operator shall ~~contemporaneously~~ track each ~~compliance event~~ monitoring, testing, and inspection events for each ~~source~~ unit subject to the ~~EMT~~ requirements of this Part, and shall comply with the following:

(a) data gathered during each monitoring, testing, or inspection ~~or testing~~ event shall be ~~contemporaneously~~ uploaded into the ~~database~~database system(s) as soon as practicable, but no later than three business days ~~of~~ after each ~~compliance event~~monitoring, testing, or inspection event or when final reports are received.

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

(~~10~~9) Upon demonstration of good cause, t~~T~~he 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. The owner or operator may request a hearing on whether good cause was demonstrated or whether the recommendations approved by the department must be implemented.

Comment on 20.2.50.112(A)(3): Redline required as barcode, QR coding, and other tracking devices have been shown to be difficult in implementation. The EMT system is unprecedented in its prescriptiveness and is even more onerous than a system required in an extreme nonattainment area (San Joaquin Valley, CA). The cost of implementation and maintenance of an EMT system will be disproportionately higher than the emission reduction potential. NMOGA member companies can identify no other air quality regulations that have successfully implemented and justified the requirement for a similar system.
At this time, NMOGA has not found a currently available commercial software product suitable for oil and gas operations that will satisfy the proposed EMT system. Having each operator develop a system of such complexity will require tremendous time, cost and effort with the largest burden falling to smaller operators. Tagging devices also presents safety concerns. Some components that would be required to be tagged under this proposal operate at extremely high temperatures or are not readily accessible. Requiring placement and scanning of such tags puts personnel at risk of injury. The language in this rule does not provide a cogent statement of the anticipated environmental benefit of the EMT system, making it difficult for NMOGA to provide cost effective solutions to NMED's environmental concerns.

Comment on 20.2.50.112(A)(3)(a)-(f): Redline required to clarify this section to indicate what is intended by location (i.e., it is the latitude and longitude of the source at which the unit is located). NMOGA also referenced back to operators use of their own company-specific engineering and maintenance practices.

Comment on 20.2.50.112(A)(5): Redline required because format of the CDR is defined in substantive sections of part 50.

Comment on 20.2.50.112(A)(7): Redline required because unreliable electronic connectivity in the field is prevalent and prevents operators from accessing these database system(s) from the field. For this reason, operators need flexibility to enter field data into systems from an office or officelike setting after the field data has been gathered.

B. ~~Monitoring~~Monitoring, testing, or inspection requirements:

(1) Units ~~Sources~~ subject to emission standards and monitoring, testing or inspection ~~(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~~ unit 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~~monitoring, testing, or inspection event.

(2) An owner or operator may submit for the department's review and approval an enforceable and equivalent alternative monitoring, testing, or inspection 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~~monitoring, testing, or inspection strategy. An owner or operator shall comply with the default ~~monitoring~~monitoring, testing, or inspection requirements required under the applicable Section and shall not operate under an alternative ~~monitoring~~monitoring, testing, or inspection strategy until it has been approved by the department.

(3) ~~Each~~ For each monitoring, testing or inspection event ~~(e.g. testing, inspection, parametric monitoring)~~ owners, operators, or their authorized representatives shall ~~be initiated by an initial scanning of the EMT, the~~

~~results of which shall then be 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~~record the ~~following information~~information required by the applicable sections of this Part~~:~~

~~**(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.~~

Comment on 20.2.50.112(B)(3)(a)-(e): Redline required as the individual sections of this Part specify with more precision what is required for that unit/source or activity.

C. Recordkeeping requirements:

(1) Within three business days of a ~~monitoring~~monitoring, testing, or inspection event or within three business days of when final reports of monitoring, testing or inspection results are received, an electronic record shall be made of the ~~monitoring~~monitoring, testing, or inspection event and shall include ~~the following data~~the information required by the applicable sections of this Part.~~:~~

~~**(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 five years.~~

Comment on 20.2.50.112(C)(1): Redline required to accommodate for lead time on third party reports (e.g., stack tests).

Comment on 20.2.50.112(C)(1)(a)-(e): Redline required as the individual sections of this Part specify with more precision what is required for that unit/source or activity. It is confusing for an operator to have to review two sections to understand comprehensively what records it needs to keep for specific equipment.

Comment on 20.2.50.112(C)(3): Redline required NMED has authority to require compliance certifications and to require those to be submitted to the agency as part of its general enforcement powers; however, the agency has no authority to inject air compliance requirements into transactions between third parties. Not only does this requirement interfere with negotiation strategy of a seller, which sometimes may be "as is, where is", it interferes with the sellers ability to negotiate the traditional elements of a sales agreement (representations, warranties, indemnity, etc). It clearly creates a disadvantage for sellers with operations subject to the rule and thus may violate the U.S. Constitution Commerce clause by creating a rule that burdens interstate commerce by requiring operators in limited areas of the state to take an action that may impact the value or salability of their facilities versus operators in other parts of the state or out of state. If owners or operators economically in need of divesting assets cannot sell their facilities to buyers with the means to operate the facilities, sellers may be forced to prematurely shut in an otherwise viable operation, thereby wasting those resources and impacting royalty holders.

Even if this requirement can overcome the potential Constitutional issues, the agency is not considering the complexity and scope of many transactions. Some transactions do not result in a change of operatorship, for example, a Non-Operated Owner under a Joint Operating Agreement may engage in a sale of a partial ownership interest in a given facility. That doesn't constitute a change of operatorship of the equipment because the Operator will still operate that equipment under the Joint Operating Agreement. It's not uncommon for oil and gas transactions to involve a sale of an entire field with 1000s of facilities in a short period of time where requiring this certification could be very difficult given the time frame outlined. As a result, the time frame could unnecessarily delay or ultimately prevent a transaction from occurring. Further, the three months before transfer of ownership is also problematic since many transactions include a two-step signing and closing process, the first to enter into an agreement to sell, followed by a closing and formal interest conveyance that may be months later. During this time, the seller continues to own and/or operate the assets while negotiations continue. Introducing a compliance evaluation at *or near the end of a transaction process may upset months of negotiation. It is also unclear how the proposed certification requirement would work in conjunction with the compulsory pooling process, which include operatorship over defined development activities and associated facilities, but not the ownership of such facilities. Finally, this requirement has no reasonable relationship to the statutory requirement to regulate sources in areas that exceed 95% of the ozone NAAQS and it does not meet the statutory criteria to be more stringent than federal standard. EPA has no such regulations and this interference in an arms-length negotiation has no relationship to protecting public health and the environment.*

D. **Reporting requirements:** Within ~~24 hours~~three business days 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. If the department requests CDR from multiple facilities, additional time shall be given as appropriate.

Comment on 20.2.50.112(D): Redline required as 24 hours is not reasonable. NMED air permits specify that data must be provided within 3 business days from the request, and that has been workable. Unexpected circumstances may also warrant an extension and that option should be made available.

[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~~well production facility, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations, with a site-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. Non-road engines as defined in 40 C.F.R. 1068.30 are not subject to 20.2.50.113 NMAC.

Comment on 20.2.50.113(A): Redline required to remove non-road engines from the scope of the rule. Under 42 U.S.C. § 7543(e)(1), Congress expressly preempted states from adopting or attempting to enforce any standard or other requirement relating to the control of emissions from (1) new nonroad engines used in construction/farm equipment or nonroad vehicles with less than 175 horsepower, or (2) new locomotives or new nonroad engines used in locomotives. 42 U.S.C. § 7543(e)(1). For any new or used nonroad engine or vehicle not addressed in § 7543(e)(1), Congress granted California exclusive authority to adopt standards and other requirements for the control of emissions. 42 U.S.C. § 7543(e)(2)(A). States other than California may promulgate such standards only if the effective date is delayed for 2 years and the emission standards are identical to provisions adopted by California through the statutorily-prescribed process. 42 U.S.C. § 7543(e)(2)(B). It is not enough that state standards are equally protective or substantially similar; they must be identical. Id. By expressly granting California exclusive authority to establish nonroad engine standards, Congress impliedly preempted any state other than California from adopting such standards for nonroad engines and vehicles within the scope of § 7543(e)(2). Engine Mfrs. Ass'n v. U.S. E.P.A., 88 F.3d 1075, 1087-88 (D.C. Cir. 1996) ("states must be preempted from adopting any regulation for which California could receive authorization."); Pac. Merch. Shipping Ass'n v. Goldstene, 517 F.3d 1108, 1113 (9th Cir. 2008) ("we join the D.C. Circuit and hold that the implied preemption of § 209(e)(2) applies to 'any nonroad vehicles or engines,' including new and non-new sources."). New Mexico's proposed standards are not identical to non-road engine standards adopted by California and are therefore preempted under 42 U.S.C. 7543(e).

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 or engines that are subject may comply with the requirements through an alternative Compliance Plan of 20.2.50.113 B.10.

(2) The owner or operator of an existing natural gas-fired spark-ignition engine shall complete an inventory of all existing engines subject to this Part 50 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 except as approved through an alternative Compliance Plan per 20.2.50.113 B.10. as follows:

Comment on 20.2.50.113.B(1)-(2). Redlined required to allow use of an alternative compliance plan as detailed further in comments to 20.2.50.113.B(10).

(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 PTE for NOx and VOC emissions are reduced to achieve an equivalent allowable ton per year emission as set forth in Table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC or by at least ninety-five percent per year.

(e) Owners or operators of an existing natural gas-fired spark-ignition engine are not required to comply with the emissions standards specified in table 1 of Subsection B of 20.2.30.113 NMAC if the owner or operator demonstrates that the emissions standard is technically impractical or economically unreasonable. Installation and maintenance costs and the best information available for determining technically practicable retrofit technology and control efficiency shall be considered. Owners or operators that seek to rely on this exemption must submit a justification for the technical impracticality or economic unreasonableness to the department for approval no less than ninety (90) days prior to the applicable compliance date set forth in the schedule in Paragraph (2) of Subsection B of 20.2.50.113 NMAC. If the department does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

(f) Any of the effective dates for the emissions standards set forth in Paragraph (2) of Subsection B of 20.2.50.113 NMAC may be extended at the Department's discretion for good cause shown.

Table 1 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED OR~~,~~ RECONSTRUCTED~~, OR INSTALLED~~ BEFORE THE EFFECTIVE DATE OF 20.2.50 NMAC.

~~Engine Type~~	~~Rated bhp~~	~~NO_x~~	~~CO~~	~~NMNEHC (as propane)~~
~~Lean-burn~~	~~>1,000~~	~~0.50 g/bhp-hr~~	~~47 ppmvd @ 15% O2 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~~

Maximum Engine BHP	Emission Standards (g/bhp-hr)		
	NOx	CO	VOC
4 Stroke ~~All~~ Lean Burn engines >1000 bhp (4-stroke)	2~~1~~.0	2.0	0.7
2-Stroke Lean Burns* >1000 bhp	3.0	2.0	0.7
All Rich Burn engines > 1000 bph	0.5	0.6	0.7

Comment on 20.2.50.113(B)(2)(d): Redline required as this hours reduction should be based on the number of hours that would result in an equivalent amount of reduction to the existing emissions limit, and not 95%. Asking for reductions by 95% even if an operator is currently operating near the emissions standard would require further reductions than set forth in Table 1 and is unreasonable.

Comment on 20.2.50.113(B)(2)(e): Redline required to include an opportunity for exemption based on either technical feasibility or economic reasonableness for any given individual engine. For transmission assets for example, it cannot simply limit operation of a unit and not provide natural gas to customers, and there may be no technically feasible or economically reasonable way to otherwise achieve an emission standard.
Redline required because a defined timeframe is necessary such that department can respond so that is it not open-ended request. This will ensure that operators can receive a resolution without waiting in perpetuity.

Comment on 20.2.50.113(B)(2)(f), Table 1: Redline required: Constructed and installed are redundant with current construction definition. Installation of an engine should not trigger the requirements for new engines.
Construction definition per NESHAP: Construction means the on-site fabrication, erection, or installation of an affected source. Construction does not include the removal of all equipment comprising an affected source from an existing location and reinstallation of such equipment at a new location. The owner or operator of an existing affected source that is relocated may elect not to reinstall minor ancillary equipment including, but not limited to, piping, ductwork, and valves. However,

removal and reinstallation of an affected source will be construed as reconstruction if it satisfies the criteria for reconstruction as defined in this section. The costs of replacing minor ancillary equipment must be considered in determining whether the existing affected source is reconstructed.
2-Stroke Lean Burn > 1000 bhp, Reference Colo 5-CCR-1001-9 Part E, Table 2.
Reference Colo 5-CCR-1001-9 Part E, Table 1, as applicable to 20.2.50 NMAC (JJJJ).

(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 OR~~,~~ RECONSTRUCTED, ~~OR INSTALLED~~ AFTER THE EFFECTIVE DATE OF 20.2.50 NMAC.

~~Engine Type~~	~~Rated bhp~~	~~NO_x~~	~~NMNEHC (as propane)~~
~~4 Stroke Lean-burn~~	~~>500 - <1,000~~	~~0.50 g/bhp-hr~~	~~0.70 g/bhp-hr~~
~~4 Stroke Lean-burn~~	~~≥1,000~~	~~0.30 g/bhp-hr uncontrolled or 0.05 g/bhp-hr with NOx control post-combustion~~	~~0.70 g/bhp-hr~~
~~4 Stroke Rich-burn~~	~~>500~~	~~0.50 g/bhp-hr~~	~~0.70 g/bhp-hr~~

Engine Type	Engine (bhp)	Emissions (g/bhp-hr)		
		NOx	CO	VOC
4-Stroke Lean Burn engines	>1000 bhp and < 2370	0.7	2.0	0.7
4-Stroke Rich Burn engines	>1000 bhp and < 2370	0.5	2.0	0.7
All engines	≥2370 bhp	0.3	2.0	0.7

Comment on 20.2.50.113(B)(3), Table 2: Redline required: 0.30 g/bhp-hr will effectively eliminate an entire product offering from Caterpillar, 3500 series engines (~1000-1800hp). Right now, there are effectively two engine manufacturer choices in this space, Waukesha and Caterpillar.
All emission and hp levels should ensure that product offerings are available from at least 2 engine viable/traditional options (e.g., an obscure manufacturer not traditionally in O&G space would not be considered. Caterpillar and Waukesha are the primary engine manufactures in the oil and gas space).
Reference Valor Memo - Engines and Turbines 20.2.50.113.

(4) The owner or operator of a natural gas-fired spark ignition engine with NOx 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 NOx 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 IIII 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 NOx 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.

(a) The owner or operator of an existing stationary natural gas-fired combustion turbine shall complete an inventory of all existing turbines subject to this Part 50 by July 1, 2022, and shall prepare a schedule to ensure that each subject existing turbine does not exceed the emission standards in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC except as approved through an alternative Compliance Plan per 20.2.50.113 B.9 as follows:

(i) by January 1, 20245, the owner or operator shall ensure at least thirty percent of the company's existing turbines meet the emission standards.

(ii) by January 1, 2027~~6~~, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing turbines meets the emission standards.

(iii) by January 1, 2029~~8~~, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing turbines meets the emission standards.

(iv) in lieu of meeting the emission standards for an existing stationary natural gas-fired combustion turbine, an owner or operator may reduce the annual hours of operation of a turbine such that the annual PTE for NOx and VOC emissions are reduced to achieve an equivalent ton per year emission reduction as set forth in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC or by at least ninety-five percent per year.

(v) Owners or operators of an existing natural gas-fired combustion turbine are not required to comply with the emissions standards specified in table 3 of Subsection B of 20.2.30.113 NMAC if the owner or operator demonstrates that the emissions standard is technically impractical or economically unreasonable. Installation and maintenance costs and the best information available for determining technically practicable retrofit technology and control efficiency shall be considered. Owners or operators that seek to rely on this exemption must submit a justification for the technical impracticality or economic unreasonableness to the department for approval no less than ninety (90) days prior to the applicable compliance date set forth in the schedule in Paragraph (7)(a) of Subsection B of 20.2.50.113 NMAC. If the department does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

(vi) Any of the effective dates for the emissions standards set forth in Paragraph (7) of Subsection B of 20.2.50.113 NMAC may be extended at the Department's discretion for good cause shown.

Comment on 20.2.50.113(B)(7)(a): Redline required as it is absolutely necessary that a similarly staggered schedule be set for existing turbines as for existing engines. The modifications necessary to achieve the thresholds are equally as significant, custom, costly, and time-intensive. Compared to engines, the same number of emission units, if not more, are impacted. NMOGA members have contacted suppliers and received estimated delivery dates stretching into 2028 for possible delivery so the January 1, 2028 deadline is not feasible.

Comment on 20.2.50.113(B)(7)(a)(v): Redline required to include an opportunity for exemption based on either technical feasibility or economic reasonableness for any given individual engine. For transmission assets for example, it cannot simply limit operation of a unit and not provide natural gas to customers, and there may be no technically feasible or economically reasonable way to otherwise achieve emission standard.
Redline required because a defined timeframe is necessary such that department can respond so that is it not an open-ended request. This will ensure that operators can receive a resolution without waiting in perpetuity.

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

For each applicable natural gas-fired combustion turbine constructed or reconstructed ~~and installed~~ before theeffective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than the schedule set forth in Paragraph (7)(a) of Subsection B of 20.2.50.113 NMAC~~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,~~4,000 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

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)
≥4~~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 NOx cControl post-combustion~~	~~10 Uncontrolled or 1.8 with Control~~	5

Comment on 20.2.50.113(B)(7), Table 3, Part 1: Reference Valor Memo - Engines and Turbines 20.2.50.113.
Redline required as CO is not an ozone precursor.
Redline required as SCR is the only available option to achieve 50 ppmvd thresholds on these smaller units. The cost of putting SCR on a unit between 1,000 and 4,000 bhp is unreasonable at approximately $108,000/ton. This is categorically economically infeasible. In lieu of the 50 ppmvd, NMOGA recommends that the rule follow 40 CFR 60 KKKK.
Redline required as New Mexico has many existing turbines in the smallest category that will be unable to meet the proposed standard without add-on control. A higher emissions level, congruent with Subpart KKKK, will allow for DLN where it's available to be retrofit and allow the smaller turbines, for which DLN in not available, to continue to operate. Many, if not all, of the turbines that fall into this smallest category are Subpart GG (or pre-NSPS) turbines.

Sections 20.2.50.2 and 20.2.50.7 clearly state that the scope and objective of the Part is to establish emissions standards for ozone precursors, volatile organic compounds (VOC) and nitrogen oxides (NOx), in specific counties. As such, including emission standards, monitoring, recordkeeping, reporting, and testing requirements for CO should not be included in the rulemaking. In the event that NMED does not remove all references to CO in this proposed ozone rule, a level of 50 ppm for existing sources should be established.

Comment on 20.2.50.113(B)(7), Table 3, Part 2: Redline required: Per the NOx standards proposed in the other size categories, the intent of the proposed NMED rule is for compliance to be achieved with dry low NOx combustion retrofits. The 25ppm NOx level is not an appropriate standard for the 1000 to 5000 hp turbine category.
NMED modeled the proposed ozone rule after Pennsylvania's GP-5 rule but did not adopt all of the applicability language with respect to existing sources. GP-5 does not impact pre-2013 units. In GP-5, units constructed on or after February 1, 2013, but prior to August 8, 2018 have to meet either 25 or 15 ppm NOx depending on their size. The NMED proposed rule impacts all existing units with no consideration for date of construction. Further background on the GP-5 rule development process is that there were no turbines in Pennsylvania in the 1000-5000 hp range installed on or after February 1, 2013, but prior to August 8, 2018 so no existing units were affected. As such, it did not come to light that the NOx emission standards in this size category are not technically achievable or commercially available from turbine manufacturers. Add-on control, specifically selective catalytic reduction, would be necessary to achieve the proposed standards on many vintage turbine units which do not have DLN (dry low NOx) capabilities.
Reference Valor Memo - Engines and Turbines 20.2.50.113.

(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**~~**(9)** The owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675~~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.

Comment on 20.2.50.113(B)(9): Redline required because, by definition, emergency engines are allowed to operate more than 100 hours in the case of an emergency. The 100 hours is the limit on maintenance/testing (i.e., non-emergency use). Based on size/use of these units, emergency engines must be exempt from this Part 50. We think this was NMED's intent and this revision aims to clarify.

(10) An owner or operator may elect to comply with the standards established in 20.2.50.113.B through development and implementation of an Alternative Compliance Plan approved by the Department instead of achieving the standards established in 20.2.50.113.B for each engine or turbine. The Alternative Compliance Plan must include the list of engines or turbines subject to the standards included in the plan and must include a demonstration that the total allowable

regulated emissions under the Alternative Compliance Plan do not exceed the total allowable regulated emissions allowed under the emissions standards of this Part and that the owner or operator will achieve emissions under the Alternative Compliance Plan consistent with the schedules set forth in this Part. The department must approve an Alternative Compliance Plan that meets this condition unless the Division identifies that the total allowable emissions allowed under the Alternative Compliance Plan do not meet or are not less than the total allowable emissions under the emissions standards of this Part.

Comment on 20.2.50.113(B)(10) (added): Redlined required to allow owners and operators flexibility in achieving the emissions reductions required by the rule. As detailed elsewhere, NMOGA has serious concerns about the technical and economic feasibility of this rule, particularly when the reductions are applied on a per-engine basis. By allowing owners and operators to achieve the emissions reductions on a total allowable regulated emissions basis, owners and operators will be able to achieve the same environmental benefits without incurring unnecessary costs.

(11) A short term replacement engine may be substituted for any engine regulated under 20.2.50.113 consistent with any applicable air quality permit containing allowances for short term replacement engines, including, but not limited to, New Source Review and General Construction Permits issued under 20.2.72 NMAC. A short term engine replacement is not considered a "new" engine for purposes of 20.2.50 NMAC, unless the engine it replaces is a "new" engine within the meaning of 20.2.50 NMAC. The reinstallation of the existing engine after removal of the short replacement engine is not considered a "new" engine under 20.2.50.113 unless the engine was "new" prior to the temporary replacement.

Comment on 20.2.50.113.B(11). Redline required to allow use of short term replacement engines consistent with existing allowances in NMED's general oil and gas permit and NSR permit standard conditions. Engines need to be taken out of service from time to time for maintenance or repair, and operators need flexibility to use replacement engines to continue operations. NMOGA is concerned that this routine activity may subject replacement of existing engines to "new" emissions standards based on NMED's broad definition of construction. NMOGA does not believe NMED intends this outcome and has added this provision to address this concern.

C. Monitoring, testing, and inspection requirements:

(1) Maintenance and repair for a spark-ignition engine, compression-ignition engine, and stationary combustion turbine shall be consistent with manufacturer specifications as stated in 20.2.50.112 NMAC. Maintenance consistent with an applicable NSPS or NESHAP standard shall be deemed compliance with 29.2.50.113.C(1). ~~meet the minimum manufacturer recommended maintenance schedule~~unit~~. 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.~~

Comment on 20.2.50.113(C)(1): Redline required to substitute defined term from section 20.2.50.112 as operators have developed their own maintenance schedules, in particular for older engines, where manufacturer recommendations may not be available or are outdated. Compliance with NSPS and NESHAP standards should also be sufficient to demonstrate proper maintenance.

Comment on 20.2.50.113(C)(1)(a)-(b): Redline required as these subparts are recordkeeping requirements, not monitoring requirements. Recordkeeping related to maintenance activities are discussed in the Recordkeeping section.

(2) Catalytic converters (oxidative, selective and non-selective) and AFR controllers shall be maintained according to manufacturer's specifications as stated in 20.2.50.112 NMAC ~~good operational and maintenance practices or 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 ~~performing an initial emissions test, followed by annual tests, for NOx, CO, and non-methane non-ethane hydrocarbons (NMNEHC) using a portable 27 analyzer or U.S. EPA reference method.~~ within 180 days of the effective date applicable to the unit as defined by Subsection B (2) and (7) or, if installed more than 180 days after the effective date, within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after initial startup of such unit. Compliance with the applicable emission standards shall be demonstrated by performing an initial emissions test for NOx and VOCs, as defined in 40 CFR 51.100(s) using U.S. EPA Reference Methods or ASTM D6348. Periodic monitoring demonstrating compliance with the allowable emission limits shall be conducted annually and may be demonstrated utilizing a portable analyzer or EPA Reference Methods. For units with g/hp-hr emission standards, the engine load shall be calculated using the following equations or other alternative methods:

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

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

Where: LVH = lower heating value, btu/scf, or btu/gal, as appropriate; and
BSFC = brake specific fuel consumption

If the manufacturer's rated BSFC is not available, an operator may use an alternative load calculation methodology based on available data.

(a) emissions testing events shall be conducted within 10 percent of 100 percent peak (or the highest achievable) load. ~~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 D6522. 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.

(c) the default time period for a test run shall be at least 20 minutes.

(d) an emissions test shall consist of three separate runs, with the arithmetic mean of the results from the three runs used to determine compliance with the applicable emission standard.

(e) during emissions tests, pollutant and diluent concentration shall be monitored and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing U.S. EPA reference method 19. This information shall be included with the periodic test report.

(f) stack gas flow rate shall be calculated in accordance with U.S. EPA reference method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (Btu/scf). The owner or operator shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months before the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using U.S. EPA reference methods 1 through 4 or through the use of manufacturer provided fuel consumption rates.

(g) upon request by the department, an owner or operator shall submit a notification and protocol for an initial or annual emissions test.

(h) emissions testing shall be conducted at least once per calendar year. Emission testing required by Subparts GG, IIII, JJJJ, or KKKK of 40 CFR 60, or Subpart ZZZZ of 40 CFR 63, may be used to satisfy the emissions testing requirements if it meets the requirements of 20.2.50.113 NMAC and is completed at least once per calendar year.

Comment on 20.2.50.113(C)(3): Redline required to replace with term manufacturers specification as defined in 20.2.50.112 as this specific manufacturer's data is frequently not available for most units older than 2000. Thus, an alternate calculation must be allowed. BSFC is regularly determined through current engineering practices and does not rely on manufacturer's rate. Changes to the timing of performance tests also made for consistency with 40 C.F.R. 60.8(a).

Comment on 20.2.50.113(C)(3)(a): Redline matches language in NSPS Subpart JJJJ.

(4) The owner or operator of equipment operated less than 500 hours per year shall monitor the hours of operation using a non-resettable hour meter and shall test the unit at least once per 8760 hours of operation in accordance with the emissions testing requirements in Paragraph (3) of Subsection C of 20.2.50.113 NMAC.

(5) An owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675~~operated for less than 100 hours pe~~ shall monitor the hours of operation by a non-resettable hour meter.

(6) An owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) or Paragraph (7) of Subsection B of 20.2.50.113 NMAC shall monitor the hours of operation by a non-resettable hour meter.

~~(7) Prior to monitoring, testing, inspection, or maintenance of an engine or turbine, the owner or operator shall scan the EMT, and the monitoring data entry shall be made in accordance with the requirements of 20.2.50.112 NMAC.~~

D. Recordkeeping requirements:

(1) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain a record in accordance with 20.2.50.112 NMAC for the engine or turbine. The record shall include:

(a) the make, model, serial number, ~~and EMT~~ for the engine or turbine;

(b) a copy of the maintenance and repair schedule for the engine, turbine, or control device as recommended by the manufacturer or as developed consistent with good operational and maintenance practices~~manufacturer recommended maintenance and repair schedule~~;

(c) all inspection, maintenance, or repair activity on the engine, turbine, and control device, including:

(i) the date and time of an inspection, maintenance or repair;

(ii) the date a subsequent analysis was performed (if applicable);

(iii) the name of the ~~personnel~~ person(s) conducting the inspection, maintenance or repair;

~~**(iv)** a description of the physical condition of the equipment as found during the inspection;~~

(~~v~~iv) a description of maintenance or repair activity conducted; and

(~~vi~~v) the results of the inspection and any required corrective actions.

(2) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain records of initial and annual emissions testing for the engine or turbine for a period of 5 years. The records shall include:

(a) the make, model, and serial number~~, and EMT~~ for the tested engine or turbine;

(b) the date and time of sampling or measurements;

(c) the date analyses were performed;

(d) the name of the ~~personnel~~ person(s) and the qualified entity that performed the analyses;

(e) the analytical or test methods used;

(f) the results of analyses or tests;

(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 as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 ~~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) or Paragraph (7) 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 NOx and VOC emission calculation, based on the engine's actual hours of operation, to demonstrate that an equivalent allowable ton per year emission as set forth in Table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC or the ninety-five percent emission reduction requirement is met.

(5) An owner or operator claiming an exemption under Paragraph 2(e) or Paragraph (7)(a)(v) of Subsection B of 20.2.50.113 must maintain records for each engine or turbine, as applicable, demonstrating that the exemption applies.

(6) An owner operator that received an extension of the effective dates for an emissions standards set forth in Paragraph (2) or Paragraph (7) of Subsection B of 20.2.50.113 NMAC must maintain records of the extension for good cause shown.

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:

Comment on 20.2.50.114: NMOGA recommends that the Compressor Seals section be completely removed from the proposed

rule. According to the ERG memo, total emissions from compressor seals (VOCs) is 0.006% of total VOC emissions from compression, which is estimated at 13 tons/year. The proposed rules would at best only reduce the tonnage by 6 tons/year, or 0.005% of the calculated VOCs post rule. Because it is not common practice to collect the gas from compressor seals, there is no industry standard for how to mechanically solve the issue. It is most certainly not the "low hanging fruit" for NMED. Short of striking the entire section, NMED should remove the "collect compressor vents under negative pressure" statement allowing operators to determine most effective method of collecting that vent, especially because a solution is not common practice.
Reference Valor Memo - Engines and Turbines.

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~~well production facilities and their associated tank batteries 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~~well production facilities and their associated tank batteries 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 with wet seals 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.~~

(5~~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.

Comment on 20.2.50.114(B)(2)(b): Redline required as "under negative pressure" is overly prescriptive; raises mechanical integrity, oxygen entrainment, and safety concerns; and does not allow flexibility for new technology or new facility concepts. NMED should keep requirement to have closed vent system and control but leave it up to the operator to determine the best method to execute.

C. Monitoring, testing, and inspection 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~~monitoring, testing, or inspection 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 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 as designed ~~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~~monitoring, testing, or inspection requirements in 20.2.50.115 NMAC.

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

Comment on 20.2.50.114(C)(3): Redline to align with above comment [20.2.50.114(B)(2)(b)].

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 or reconstruction ~~or modification~~ of the centrifugal compressor;

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

(d) the type, make, model, and identification number or equivalent identifier 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~~,~~ or reconstruction~~, or modification~~ of the reciprocating compressor; and

(c) the ~~monitoring~~monitoring, testing, or inspection required in Subsection C of 20.2.50.114 NMAC, including:

(i) the number of hours of operation since the effective date, initial startup after the effective date, or the last rod packing replacement, as applicable;

(ii) data showing effectiveness of ~~the records of pressure in~~ the rod packing emissions collection system, as applicable, and

(iii) the time and date of the monitoring, testing or inspection, the ~~personnel~~ person(s) conducting the monitoring, testing or inspection, ~~a notation of which checks required in Subsection C of 20.2.50.114 NMAC were completed,~~ a description of any problems observed during the monitoring, testing or 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.

Comment on 20.2.50.114(D)(1)(b): Redline required because definitions for construction and reconstruction include modification.

Comment on 20.2.50.114(D)(2)(c)(ii): Redline required to align with striking negative pressure. Alternative methods should be allowed to show effectiveness (e.g., bubble soak test, helium mass spec test, etc).

Comment on 20.2.50.114(D)(2)(c)(iii). Redline recommended because the reference to notations for checks required under Subsection C is vague. The rule should specify the recordkeeping requirements with specificity to give the regulated community fair notice.

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 AND CLOSED VENT SYSTEMS:

A. Applicability: These requirements apply to control devices and closed vent systems as defined in

20.2.50.7 NMAC and used to comply with the emission standards and emission reduction requirements in this Part.

Comment on 20.2.50.115: Redline for clarification as this section also contains requirements for closed vent systems.

B. General requirements:

(1) Control devices used to demonstrate compliance with this Part shall be installed, operated, and maintained consistent with manufacturer specifications; or installed, operated, and maintained in accordance with ~~, and~~ good ~~engineering~~ operating 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 the reasonably expected range of inlet VOC or NOx concentrations or volumes. ~~fluctuations in emissions of VOC or NOx.~~

~~(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~~3) The owner or operator shall inspect visually, or consistent with federally approved inspection methods, control devices ~~used to comply with this Part~~ at least monthly to identify defects, leaks, and releases. ~~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.~~

(4~~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~~5) 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 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 the reasonably expected range of ~~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~~ assessment certified by a qualified professional engineer or an in-house ~~engineer~~ employee with expertise regarding the design and operation of ~~the~~ closed vent systems 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~~ the in-house ~~engineer~~ employee 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~~employee: "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~~6) The owner or operator shall keep manufacturer specifications for all control devices installed after the effective date on file. The information shall include the manufacturer name, make, and model and relevant capacity and efficiency data.~~:~~

~~(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,.~~

Comment on 20.2.50.115(B)(1): Redline required because, f many pieces of equipment, particularly equipment purchased before the applicability of this rule, manufacturer specifications may not be readily available. In addition, experience in the field sometimes dictates adopting procedures that differ in some respects from manufacturer recommendations.

Comment on 20.2.50.115(B)(2): Redline required as control devices are designed for anticipated range of flowrates, pressures, and compositions. However, in many cases, compositions, flows, and pressures change during normal operations in ways that are not anticipated. Engineers can only design to predictable conditions.

Comment on 20.2.50.115(B)(3): Redline required to clarify that inspections conducted pursuant to federal standards, such as 40 C.F.R. Part 60 Subparts OOOO and OOOOa, are adequate to meet the monthly inspection requirement. See, e.g., 40 C.F.R.

60.5416(c) (requiring monthly inspection of certain closed vent systems). These federal inspections are designed and proven to achieve the same objective as NMED's rule—to ensure proper performance of control device systems.

Comment on 20.2.50.115(B)(4): Redline required as this statement is counter intuitive. A control device with a certain DRE% will only combust or destruct gas up to that DRE%. Any unburnt gas (i.e., 100-DRE) percent must be assumed to be directly vented to atmosphere. As written, the statement of "unburnt gas is not directly vented to the atmosphere" implies a 100% DRE device.

Comment on 20.2.50.115(B)(5): Redline required to align the standard with 40 C.F.R. Part 60, Subpart OOOOa. NMED has largely incorporated the language of 40 C.F.R. 60.5411a(d). However, unlike NMED's proposal, EPA did not include pneumatic controllers because, as it has expressed elsewhere, use of closed vent systems with pneumatic controllers is not a "viable control option." 81 Fed. Reg. 35824, 35879 (Jun. 3, 2016). Pneumatic controller actuations require a sudden change in pressure, and any back pressure on the device could impact its ability to function, making application of closed vent systems impractical.

Comment on 20.2.50.115(B)(5)(a), (b): It is unreasonable to require that "all" emissions be controlled at all times as systems must be designed for expected conditions and not every possible condition can be anticipated.

Comment on 20.2.50.115(B)(5)(c): Redline required to indicate that an "assessment" can be an open loop or closed loop vapor control system approach. The closed loop vapor control system approach, for example, utilizes a series of feedback control loops from storage vessels to control upstream equipment based on storage vessel pressure. This approach has been deemed "closed loop control" method, and has been approved as acceptable substitute for closed vent system analysis (which is a theoretical model) in recent consent decrees (ref High Point Resources, KPK Kauffman) and EPA's new owner self audit agreement. "Assessment" can either mean the results for a theoretical model (i.e., open loop method) or another method such as the results of a functioning automation system (e.g., closed loop vapor control system).

Comment on 20.2.50.115(B)(5)(c)(i)-(ii). Redline required because, in many instances, in-house experts are better trained and capable of assessing such systems than someone that is a licensed professional engineer. There are likely very few licensed professional engineers that are actually versed in the details of such systems. Requiring operators to find and use such individuals would create undue hardship with no emissions benefit.

Comment on 20.2.50.115(B)(6)(a)-(e). For existing sources, manufacturer's specifications may have never existed, may have been lost, or may no longer be maintained by the manufacturer. Moreover, even where these specifications do exist, they may not be appropriate for some equipment due to enhancements in technology or information gleaned based on company or industry experience using the equipment in our specific service. To the extent that these specifications are needed to demonstrate compliance with technical standards, the rule should permit alternative means of demonstrating compliance.

C. Requirements for open flares:

(1) Emission standards:

(a) The flare shall be properly sized and designed to ensure proper combustion efficiency to 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 outside the bounds of the design capacity.~~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~~D) of this Subsection) with a continuous pilot flame or ~~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.~~

(ii~~i~~) a new flare controlling a continuous gas stream shall be equipped with a continuous pilot flame or auto-igniter upon startup.

~~**(iv)**~~ **(c)** the owner or operator shall equip each existing flare (except those flares required to meet the requirements of paragraph (D) of this Subsection) with an automatic ignitor, continuous pilot, or technology that alerts the operator that the flare may have malfunctioned no later than two years after the effective date. ~~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~~d) 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 or ~~,~~ 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~~e) the owner or operator shall operate a flare with no visible emissions, except for 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. The observation may be terminated if visible emissions are identified and recorded or action is taken to address visible emissions.

(~~e~~f) the owner or operator shall initially attempt to repair the flare within three business days of any thermocouple or other flame detection device alarm activation.

Comment on 20.2.50.115(C)(1)(a): ~~While operators can attempt to ensure combustion, there are certain events that are outside of an operator's control. Therefore, the owner or operator cannot guarantee that combustion will be maintained for the duration of time that gas is sent to the flare. However, t~~The owner or operator can guarantee that flare is designed to ensure proper combustion efficiency. ~~Additionally, this~~The proposed language aligns with the recently adopted NMOCD rule, 19.15.27.8.E(3) NMAC. In addition, the provisions of 20.2.50.115.C.(1)(b)-(f) provide assurance that the flare will combust gases sent to it.

Comment on 20.2.50.115(C)(1)(b)(i)-(ii): Redline required to align with NMOCD venting and flaring rule. NMOCD does not allow for manual ignition.

Comment on 20.2.50.115(C)(1)(b)(i): A flare equipped with an auto igniter is inherently equipped with a system to ensure the flare is operated with a flame present at all times because it auto ignites in the presence of gas.

Comment on 20.2.50.115(C)(1)(d): Redline required to align with OCD Waste Rule. As that rule and this one are focused on gas waste and gas related emissions, respectively, it is appropriate to apply flexibilities like this one based upon gas rate through the site.

Comment on 20.2.50.115(C)(1)(e): Redline required because under the proposed standard, if 30 seconds of visible emissions are observed during a 15-minute period, further evaluation is not necessary to evaluate compliance with the standard. As written, the rule appears to require the observation to continue, even if visible emissions violating the standard are observed. NMOGA would prefer the flexibility to end the observation once a violation is observed so that it can begin to address the underlying cause.

Comment on 20.2.50.115(C)(1)(f): Redline required because it may take longer than three business days to repair. For flares where thermal monitoring is appropriate, NMOGA agrees monitoring alarms is appropriate. The regulation should include a qualifier to clarify the narrow scope of this requirement (e.g., "thermocouple or other flame detection device alarm activation"). NMOGA also requests the provision not require recording false alarms due to wind or other weather- related events. For example, wind may create distance between the thermocouple and the flame and trip the alarm, even though the flame continues to be ignited.

(2) Monitoring, testing, and inspection requirements:

(a) the owner or operator of a new 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~~b) the owner or operator shall~~, at least quarterly, and~~ upon observing visible emissions for a period of time 30 seconds, 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. The observation may be terminated if visible emissions are identified and recorded or action is taken to address visible emissions.~~to address the visible emissions.~~

~~**(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~~

(c~~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.

Comment on 20.2.50.115(C)(2)(a): NMOGA requests this provision be revised consistent with the discussion above to not require retrofitting for existing facilities.

Comment on 20.2.50.115(C)(2)(b): Redline required to align with NMOCD venting and flaring rule.

Comment on 20.2.50.115(C)(2)(b): Redline required because under the proposed standard, if 30 seconds of visible emissions are observed during a 15-minute period, further evaluation is not necessary to evaluate compliance with the standard. As written, the rule appears to require the observation to continue, even if visible emissions violating the standard are observed. NMOGA would prefer the flexibility to end the observation once a violation is observed so that it can begin to address the underlying cause.

Comment on 20.2.50.115(C)(2)(d): Redline required to remove EMT as described in General Provisions.

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

(a) any instance of thermocouple or other flame detection device 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~~ person(s) conducting the inspection, and any maintenance activity performed;

(b) the results of any~~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 most recent gas analysis (sampled or modeled) for the gas being flared, including VOC content and heating value, if any; 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~~,~~

Comment on 20.2.50.115(C)(3)(c): Redline required to align with NMOCD venting and flaring rule.

Comment on 20.2.50.115(C)(3)(d): Redline required as gas samples may be representative samples from adjacent or representative facilities. Redline clarifies to retain sample reports if available. Redline further makes clear that the results of the gas analysis for the gas flared may use modeling (based on a liquids analysis) of the gas going to the flare.

(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 be properly sized and designed to ensure proper combustion efficiency to 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 each new~~an~~ ECD/TO with a continuous pilot flame or an auto-igniter. New ECD/TO with a continuous pilot flame shall be equipped with a system to ensure the ECD/TO is operated with a flame present at all times when gas is being sent to ECD/TO. Existing ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter no later than two years after the effective date. ~~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~~c) 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. The observation may be terminated if visible emissions are identified and recorded or action is taken to address visible emissions.

(2) Monitoring, testing, and inspection requirements:

(a) the owner or operator of a new~~n~~ ECD/TO with a continuous pilot shall continuously ~~or an auto igniter~~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 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 for a period of time exceeding 30 seconds, 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. The observation may be terminated to if visible emissions are identified and recorded or action is taken address visible emissions.

~~(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 a thermocouple or other flame detection device ~~n~~ 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~~ person(s) conducting the inspection, and any maintenance activities performed;

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

(c) the results of the most recent gas analysis (sampled or modeled) for the gas being combusted, including VOC content and heating value~~.~~, if any,

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

Comment on 20.2.50.115(D)(1)(a): Redline to align with comment in flare section above (20.2.50.115(C)(1)(a):)

Comment on 20.2.50.115(D)(1)(c): Redline required to align with NMOCD requirements for flares (20.2.50.115(C)(1)(a)

Comment on 20.2.50.115(D)(2)(a): Redline required as auto-igniter ECD/TOs do not have a continuous flame and should not be included in this provision. NMOGA also requests this provision be revised consistent with the discussion above to not require retrofitting for existing facilities.

Comment on 20.2.50.115(D)(2)(c): Redline required to remove EMT as described in General Provisions.

Comment on 20.2.50.115(D)(3)(c): Redline required as gas samples may be representative samples from adjacent or representative facilities. Redline clarifies to retain sample reports if available. Redline further makes clear that the results of the gas analysis for the gas flared may use modeling (based on a liquids analysis) of the gas going to the flare

E. Requirements for vapor recovery capture units (VRCU):

(1) Emission standards:

(a) the owner or operator shall operate the VRCU 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~~VRCU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRCU~~VRU.~~ during the period of VRCU downtime unless otherwised approved in state permit. Alternatively, the owner or operator may shut down and isolate the source being controlled by the VRCU.

(2) Monitoring, testing, and inspection ~~Requirements~~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~~~~VRCU~~ ~~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 VRCU downtime or alternatively keep records of the equipment shut down and isolated as well as the time period over which it was shut ~~down.~~.down or records regarding compliance with the state permit.

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

Comment on 20.2.50.115(E)(1)(b): Redline required as an operator should have the option of not operating a unit (e.g. Tank) with a VRCU rather than having redundant control or backup control. For example, an operator could shut-in a well(s) to service a VRCU on the tanks receiving hydrocarbon fluid from that well (s) rather than have redundant control systems.

Comment on 20.2.50.115(E)(3): Redline required as record keeping is addressed under LDAR section. Redline required as an operator should have the option of not operating a unit (e.g. Tank) with a VRCU rather than having redundant control or backup control. For example, an operator could shut-in a well(s) to service a VRCU on the tanks receiving hydrocarbon fluid from that well (s) rather than have redundant control systems.

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

(1) the certification of the closed vent system where applicable and ~~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.

[20.2.50.115 NM–C - N, XX/XX/2021]

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:

A. Applicability: ~~Wellhead sites~~Well production facilities, 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. Equipment leak and fugitive emissions -monitoring required by New Source Performance Standards, including but not limited to Subpart OOOO and Subpart OOOOa, 40 C.F.R. Part 60, as may be revised, may be used to satisfy the requirements of this 20.2.50.116 NMAC. A component is subject to the requirements if it is a gas vapor or light liquid component that contacts process fluid that is at least 10% VOC by weight. Components in water and/or air service are exempt from the requirements of 20.2.50.116 NMAC. Well production facilities and gathering and boosting sites producing or handling exclusively coal bed methane are not subject to the requirements of 20.2.50.116

Comment on 20.2.50.116.A. Redlined required to exempt facilities already performing robust equipment leak monitoring under New Source Performance Standards. The ten-percent VOC threshold is added to exempt from the rule components that do not contain liquids capable of emitting meaningful amounts of VOC. Similarly, NMOGA has added the exemption for water and/or air service components because these do not leak VOCs. Coal bed methane wells or gathering and boosting sites handling coal bed methane should also be excluded because they do not have the potential to emit VOC's due to equipment leaks since the gas they produce or handle has no VOC to emit and there are no hydrocarbon liquids produced or handled

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, inspection or testing 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 ~~wellhead site~~well production facility or tank battery ~~facility~~ with an annual ~~average daily production of greater than 10 barrels of oil per day or an~~ average daily production or average daily throughput 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 an external visual inspection for defects which may include~~:~~ 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 ~~be considered a leak; and~~

~~**(e)** a leak discovered by an AVO inspection shall be tagged with a visible tag~~ repaired in accordance with Subsection E if not repaired at the time of discovery. ~~and reported to management or their designee within three calendar days.~~

(2) The owner or operator of a ~~wellhead site~~well production facility or tank battery ~~facility~~ with an annual ~~average daily production of equal to or less than 10 barrels of oil per day or an~~ average daily production or average daily throughput 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~~well production facilities or tank battery facilities:

(i) annually at facilities with a PTE less than 10~~two~~ tpy VOC;

(ii) semi-annually at facilities with a PTE equal to or greater than ~~two~~ 10 tpy and less than ~~five~~ 25 tpy VOC; and

(iii) quarterly at facilities with a PTE equal to or greater than ~~five~~ 25 tpy

(b) for gathering and boosting sites, gas processing plants, and transmission compressor stations

(i) ~~quarterly~~ semi-annually at facilities with a PTE less than 25 tpy VOC; and

(ii) ~~monthly~~ quarterly at facilities with a PTE equal to or greater than 25 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 and by the instrument manufacturer;

~~(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 nor more than, 10,000 ppm methane or n-hexane; and~~

(~~c~~b) 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) Leaks discovered pursuant to the leak detection methods of Paragraphs (3), (4) and (5) of Subsection C of 20.2.50.116 NMAC are not subject to enforcement by the department unless the owner or operator fails to perform the required repairs in accordance with Subsection E of 20.2.50.116 NMAC or keep required records in accordance with Subsection F of 20.2.50.116 NMAC.

(~~6~~7) 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.

Comment on 20.2.50.116(C): Redline required as the "and" here creates significant confusion where 112 is a default monthly inspection. It also conflicts with 112's statement that default is monthly unless otherwise stated in the specific rule section. Ultimately, the reference is unnecessary when this leak program is a monitoring program.

Comment on 20.2.50.116(C)(1). (2): Redline required to align with OCD Waste Rule. As that rule and this one are focused on gas waste and gas related emissions, respectively, it is appropriate to apply flexibilities like this one based upon gas rate through the site.

Comment on 20.2.50.116(C)(1)(a): Redline required to limit to external AVO, and not requiring equipment to be opened up for internal inspection. AVO inspections can provide opportunities for operators to identify components at a facility that are not operating properly. The proposed language may be interpreted to require operators to open seals and gaskets to visually inspect for damage. This is not a common practice during an AVO inspection and may lead to unnecessary waste not typically associated with an AVO inspection. Incorporating this practice into an AVO inspection would also pose a safety issue when opening up the equipment to visually inspect for damage. Operators have specific practices, procedures, and guidelines for *how and when to open equipment such as seals and gaskets to check for damage.*

Comment on 20.2.50.116(C)(3)(a). The thresholds and inspection frequencies set in 20.2.50.116 C(3)(a) for requiring equipment leak surveys are unnecessarily stringent, result in less reductions than estimated, and impose unreasonable costs.

1. ***The ERG evaluation is flawed.*** The evaluation of VOC control quantities and costs, performed for NMED by ERG and presented in the ERG excel workbook titled "LDAR-Reductions-and-Costs-VOC-5-27-2021_erg-06-08-2021.xlsx" overstates the reductions that would be achieved by the rule and understates the costs of such reductions.
   a. ***Types of Survey Instrument and Reduction Percentages***. ERG assumes that companies would use an equal blend of Optical Gas Imaging (OGI) and Method 21 (handheld analyzer) instruments (500 ppm detection threshold) when doing surveys and averaged the reduction percentages for these two methods.
      i. Based on 2019 GHGRP reported survey types this is an incorrect assumption. Of 2,022 reported surveys, 1,714 (85%) were reported as using an OGI imaging instrument.
      ii. For this reason, NMOGA did not include Method 21 methodologies in any of their analyses.
   b. ***Model Plants – Well Production Facilities.*** The ERG analysis relied on a "model plant" that is not representative of New Mexico and does not represent the best data available.
      i. The ERG evaluation uses reductions and costs from the US EPA's: Control Techniques Guidelines for the Oil and Natural Gas Industry. EPA-453/B-16-001. October 2016 [hereafter, "2016 CTG"]; U.S. Environmental Protection Agency, Office of Air and Radiation, Office of Air Quality Planning and Standards, Sector Policies and Programs Division Research Triangle Park, North Carolina Table 9-11 of the 2016 CTG. Specifically, ERG used reductions and costs from tables 9-11, 9-12, and 9-13 from the 2016 CTG's to estimate reductions and costs for annual, semi-annual, and quarterly inspection frequencies at well production facilities (well sites)
      ii. These tables are based on "Model Plants" that EPA used to estimate potential emissions and reductions in the 2016 CTG's
      iii. The "Model Plants" in the 2016 CTG's were established by EPA for Natural Gas Well sites, Oil Well Sites with a GOR <300 scf/bbl, and Oil Well Sites with a GOR >= 300 scf/bbl. The counts of major equipment and components (valves, connectors, etc) for these model plants were based on information from an EPA/GRI study from 1996 (gas well sites) and 40 CFR Part 98, subpart W, Tables W-1B and W-1C (component counts for oil well sites). These EPA "Model Plants" represent a generic representation of well sites and are not specific to well sites in the San Juan and Permian Basins.
      iv. Based on equipment counts reported into the US EPA's Greenhouse Gas Reporting Program (40 CFR Part 98, subpart W) well production facilities in the San Juan and Permian Basins have, on average, less pieces of major equipment, less components, and less potential equipment leak emissions than the 2016 CTG Model Plants. The GHGRP based well site Model Plants are reflective of San Juan and Permian Basin sites and should be used preferentially to the generic CTG models.
   c. ***Inaccurate Reductions – Well Production Facilities.*** The failure to rely on the correct model led to unrepresentative conclusions.
      i. Less potential for equipment leaks translates to less reductions from a leak detection and repair program. Comparing the ERG CTG based reduction estimates and the GHGRP based reduction estimates shows the effect of these differences.

Estimated Reductions Comparison - Tons Per Year VOC – OGI Surveys						
	ERG (CTG Basis)			**NMOGA (GHGRP Basis)**		
	Gas Well Site	**Oil Well Site <300 GOR**	**Oil Well Site <300 GOR**	**Gas Well Site**	**Oil Well Site <300 GOR**	**Oil Well Site <300 GOR**
Annual	0.61	0.13	0.3	0.509	0.096	0.122
Semiannual	0.917	0.199	0.451	0.764	0.143	0.183
Quarterly	1.222	0.265	0.602	1.018	0.191	0.244

      ii. Coupling these lower reductions with the costs in ERG's analysis workbook yields the following comparison of costs per ton of VOC reduction at the different survey frequencies in the proposed rule.

Costs of VOC Reductions - $ per ton of VOC reduced – OGI Surveys						
	ERG (CTG Basis)			**NMOGA (GHGRP Basis)**		
	Gas Well Site	**Oil Well Site <300 GOR**	**Oil Well Site <300 GOR**	**Gas Well Site**	**Oil Well Site <300 GOR**	**Oil Well Site <300 GOR**
Annual	$2,243	$10,343	$4,552	$2,686	$14,267	$11,226
Semiannual	$2,592	$11,954	$5,260	$3,124	$16,605	$12,975
Quarterly	$3,588	$16,553	$7,285	$4,299	$22,960	$17,973

iii. As this cost comparison table illustrates, by considering actual characteristics of well sites in the San Juan and Permian Basins rather than generic models based on old and non-specific data, the cost per ton of VOC reduction at well sites is meaningfully higher than projected by ERG.

d. ***Inaccurate Costs – Well production facilities.***

i. The costs used in the ERG analysis of 20.2.50.116 requirements for well sites are from the 2016 CTG's.

ii. In their December 2015 comments on the draft 2016 CTGs, the American Petroleum Institute (API) noted the estimated costs of leak surveys was significantly understated by EPA. The following excerpt from the API comments provide an overview of the costs underestimated by EPA.

EPA Did Not Consider Key Costs To Industry In Assessing The Cost Effectiveness Of Leak Detection Requirements Proposed.
In its cost analysis for the proposed control strategy for fugitives emissions, EPA did not adequately capture all of the costs associated with implementation of such a program. Specifically, in the cost-effectiveness evaluation, EPA underestimated the costs associated with:

- *Conducting leak surveys*
- *Completing repairs, and*
- *Maintaining the required recordkeeping, including the costs of developing and maintaining the corporate and site-specific monitoring plans.*

Further, EPA did not include several aspects beyond the cost of the actual survey work in its cost analysis, including:

- *Training of personnel*
- *Travel time and costs*
- *Equipment maintenance (e.g. monitoring device calibration)*

… Utilizing the more representative costs along with EPA's current estimates of emission reductions expected from the rule, the cost effectiveness of the proposed semi-annual OGI monitoring increases from EPA's estimate of $2,230 per well site to over $6,400 per site.

iii. Using the API cost of $6,400 per site with adjustment to a 2019 cost yields an estimated cost per ton of VOC reduction of $8,751 for the GHGRP based gas well site Model Plant and $7,253 for the 2016 CTG's gas well Model Plant.

iv. These additional costs support raising the monitoring thresholds to improve the feasibility of the rule.

2. *Percent of components leaking, survey frequency and percent VOC reduction*

a. In their December 17, 2018 comments to EPA regarding reconsideration of Subpart OOOOa (Docket ID No. EPA-HQ-OAR-2017-0483; EPA's "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration; Proposed Rule"; 83 Fed. Reg. 52056 (October 15, 2018)), the American Petroleum Institute (API) presented data from analysis of Subpart OOOOa leak surveys conducted by their member companies. API's analysis includes:

i. Two years of Subpart OOOOa Leak Survey Data for Sites Monitored at a Semi-Annual Frequency

ii. Over 6,000 total surveys across 3,482 sites

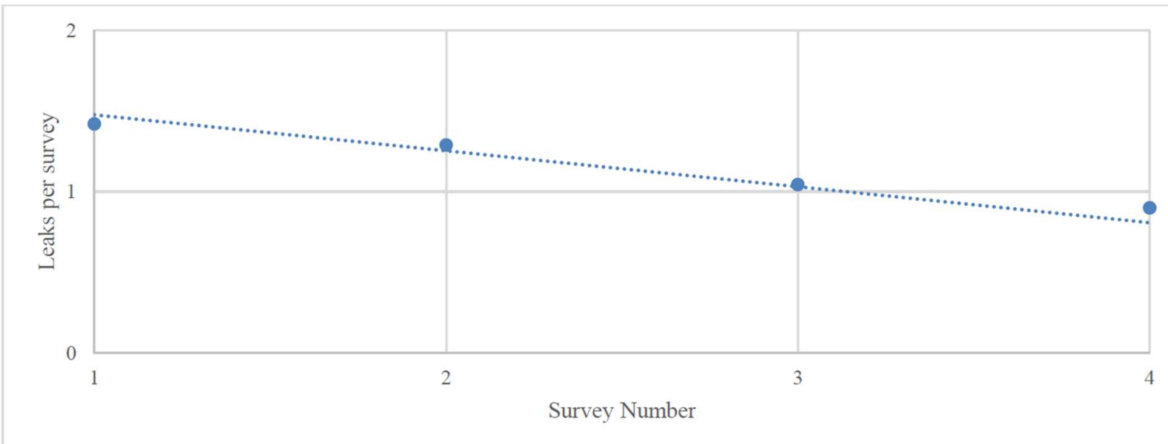
iii. Represents data from 13 different operators

b. API's analysis showed the following:

i. There are large number of sites that have no leaks (58% of initial well site surveys).

ii. The average number of leaking components per site is less than 2 components found leaking during the initial Subpart OOOOa survey and falls quickly to less than 1 leaking component found on average in subsequent surveys. These values are both below the 4 fugitive components that EPA assumed would require repair in each survey and even further below the number of leaks assumed in the EPA Leak Protocol Table 2-4 emission factors that were used to estimate emissions (See Figure 1 in Comment 1.1.3). In fact, nearly 92% of all surveys conducted across the 2-year period identified 4 or less leaking components per site.

Figure 1. Average Count of Leaks Found per Leak Survey Monitored per § 60.5397a



c. Additionally, a research study funded by the API and conducted by GHD found an overall component leak percentage of 0.42% at 67 varied upstream oil and gas sites. This peer reviewed paper "Equipment leak detection and quantification at 67 oil and gas sites in the Western United States" was published in 2019. (Pacsi, Adam & Ferrara, Tom & Schwan, Kailin & Tupper, Paul & Lev-On, Miriam & Smith, Reid & Ritter, Karin. (2019). Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. Elem Sci Anth. 7. 29. 10.1525/elementa.368.)

d. This recent data further illustrates that the estimated VOC reductions in the 2016 CTG's used to evaluate 20.2.50.116 NMAC are overstated, the costs per ton of VOC reduction are higher, and the incremental reductions from increasing the frequency of leak surveys is lower than used in NMED's contractor's analysis.

e. This further supports NMOGA's recommendation that less frequent leak surveys at higher emissions threshold are appropriate for wells and tank batteries.

Comment on 20.2.50.116(C)(3)(b). The emissions thresholds and associated leak monitoring frequencies at 20.2.50.116(C)(3)(b) are overly stringent and not supported by NMED's analysis. These thresholds and frequencies should be adjusted as indicated above to better reflect the potential reductions and costs of leak monitoring.

1. Gathering and Boosting Sites.

a. For gathering and boosting sites, ERG used reductions and costs from table 9-14 from the 2016 CTG to estimate reductions and costs for annual, semi-annual, and quarterly inspection frequencies at gathering and boosting sites. For the monthly inspection frequency case, ERM used the Colorado cost per inspection for the annual cost. ERM then used the "CTG cost effectiveness value for quarterly OGI checks for G&B x a factor of 1.5 because the cost/ton increases as the frequency increases".

b. These tables are based on "Model Plants" that EPA used to estimate potential emissions and reductions in the 2016 CTG's

c. Similar to well production facilities, the "Model Plant" in the 2016 CTG, established by EPA for Gathering and Boosting sites major equipment and components (valves, connectors, etc), is based on old and limited information from an EPA/GRI study from 1996.

d. Based on a major recent study commissioned by the US Department of Energy and led by Colorado State University (Zimmerle, Daniel, Bennett, Kristine, Vaughn, Timothy, Luck, Ben, Lauderdale, Terri, Keen, Kindal, Harrison, Matthew, Marchese, Anthony, Williams, Laurie, & Allen, David. Characterization of Methane Emissions from Gathering Compressor Stations: Final Report. United States. https://doi.org/10.2172/1506681) gathering and boosting sites have, on average, less pieces of major equipment, less components, and less potential equipment leak emissions than the 2016 CTG Model Plant.

e. Less potential for equipment leaks translates to less reductions from a leak detection and repair program. Comparing the ERG CTG based reduction estimates and the CSU/DOE study-based reduction estimates shows the effect of these differences.

VOC Tons per Year Reduced per Gathering and Boosting Site			
OGI Inspection Frequency	**ERG Estimated**	**NMOGA Estimated**	
		San Juan	**Permian**
Annual	3.91	0.746	1.853
Semiannual	5.86	1.119	2.779
Quarterly	7.81	1.492	3.705
Monthly[a]	Not Shown	1.678	4.168
For the monthly OGI survey frequency, NMOGA used 90% reduction which is the Method 21 monthly reduction percentage stated by ERG minus the 2% differential for quarterly OGI surveys vs. quarterly Method 21 surveys.			

f. Using these more current and correct reduction estimates, NMOGA calculates the following costs per ton of VOC reductions for gathering and boosting sites in the San Juan basin and gathering and boosting sites in the Permian basin.

Cost per Ton of VOC Reduction - Gathering and Boosting Site		
OGI Inspection Frequency	**NMOGA Estimated**	
	San Juan	**Permian**
Annual	$10,837	$4,362
Semiannual	$12,572	$5,061
Quarterly	$17,452	$7,025
Monthly[a]	$46,539	$18,734
[a]The annual cost for monthly OGI surveys at G&B sites is the annual cost for quarterly surveys in ERG's workbook multiplied by 3 (12 surveys/4 surveys)		

g. The reductions are less and the costs higher in the San Juan basin than the Permian basin due to the differences in gas composition between the basins. The San Juan basin field gas is about 15% by weight VOC while the Permian basin field gas is about 31.8% by weight VOC.

h. As this analysis illustrates, the cost of leak surveys at gathering and boosting stations are significantly higher than estimated by ERG and not justified as currently proposed.

i. For these reasons, NMOGA recommends the frequencies and thresholds be adjusted to better reflect the potential reductions and costs.

2. Transmission Compressor Stations

a. In the analysis conducted for NMED, ERG did not include any information or basis for VOC emissions or VOC emission reductions from transmission compressor stations. ERG does state, in their analysis workbook, that they "Used Colorado cost per inspection for the annual cost and the CTG cost effectiveness value for quarterly OGI checks for G&B." for stations with a VOC PTE <25 tpy, and they "Used Colorado cost per inspection for the annual cost. Used the CTG cost effectiveness value for quarterly OGI checks for G&B x a factor of 1.5 because the cost/ton increases as the frequency increases." for stations with a VOC PTE >= 25 tpy.

b. Since there are no estimates of VOC emissions or emission reductions, there is no basis for NMOGA or the EIB to evaluate the efficacy of the 20.2.50.116 NMAC requirements for transmission compressor stations.
c. Given the fact that natural gas handled by transmission compressor stations has been processed and most propane and heavier hydrocarbons (VOC's) removed it is almost certain that potential equipment leak VOC emissions are very low and any reductions from LDAR surveys would be correspondingly very low.
d. The VOC content of typical pipeline natural gas in the US is around 0.8% by weight VOC, contrasted with 15% by weight for produced gas in the San Juan basin and 31.8% by weight for produced gas in the Permian basin.
e. EPA did not include transmission compressor stations in the 2016 CTG because, given the lack of VOCs in the gas handled, there is little to no potential for VOC reductions to be made at them.
f. Based on the EPA 2019 Greenhouse Gas Inventory and the typical composition of pipeline natural gas in the US, the equipment leak emissions of VOC are around 0.12 tpy per transmission compressor station. Reductions from LDAR leak surveys and repair are a fraction of this dependent on the survey frequency.
g. Due to the lack of information to evaluate the appropriateness of the proposed 20.2.50.116 NMAC for transmission compressor stations, the certainty that VOC emissions would be less than 0.1 tpy/station regardless of the inspection frequency, and the extremely high cost of the miniscule potential VOC reductions, NMOGA recommends that leak surveys for transmission compressor stations be reduced as outlined above.

3. ***Gas Processing Plants***
   a. In their analysis, conducted for NMED, ERG does not document or analyze incremental VOC reductions from implementing 20.2.50.116 NMAC at gas processing plants.
   b. ERG inappropriately uses the cost per ton of VOC reduction from the 2016 CTG to analyze the average cost per ton of reduction from gas processing plants. However, the basis for the 2016 CTG LDAR reductions and costs are entirely different than and not reflective of the requirements for LDAR at gas processing plants in 20.2.50.116.
      i. The 2016 CTG's evaluated the incremental reductions and costs of an existing gas plant moving from a Subpart KKK or Subpart VV LDAR program to a Subpart VVa program. The incremental requirements in the 2016 CTG's would be monthly checks for valves and pumps, and periodic checks for connectors based on the percent that are found leaking. If >0.5% of connectors are found leaking, then all need to be checked annually; longer intervals are allowed at lower percentages of leaking connectors.
      ii. In contrast, the requirements in 20.2.50.116 are for quarterly or monthly LDAR surveys of the entire gas processing facility rather than just incremental checks of valves and pumps.
      iii. ERG does acknowledge that most, if not all, gas processing plants in New Mexico are already implementing an LDAR program under Subpart KKK or Subpart VV. ERG also documents some plants subject to the Subpart OOOOa NSPS requirements for LDAR surveys which mirror those in the 2016 CTG's.
      iv. For gas processing plants that are already implementing a Subpart VVa program under NSPS OOOOa, ERG incorrectly assigns zero cost in their analysis. However, there are no exclusions of such plants in 20.2.50.116 NMAC as proposed. NMOGA has recommended a change in the proposed rule that acknowledges compliance with LDAR requirements in Subpart OOOOa, and other NSPS's constitutes compliance with 20.2.50.116 NMAC.
   c. Without documentation of the incremental VOC reductions from implementing the proposed rule requirements at gas processing plants and correct documentation of the cost per ton of VOC reduction, there is no ability for NMOGA or the EIB to evaluate whether the requirements are appropriate or not.
   d. For these reasons, NMOGA has recommended changes which would limit the frequency of LDAR surveys at gas processing plants.

Comment on 20.2.50.116(C)(4)(a): Redline required as calibration procedures vary by type and manufacturer of instrument. This calibration requirement should cite the manufacturer's procedures.

Comment on 20.2.50.116(C)(7)(a): Redline required to align with federal rule. NMOGA finds language around scissor-lifts confusing and potentially asks operators to conduct unsafe work at unsafe heights. This practice is not routine and is done only when necessary, with significant safeguards. These safeguards, such as spotters and shutting in equipment, are generally not factored into cost-benefit and likely results in very little additional emissions reduction. Inspectors are regularly able to find leaks on top of storage tanks from the ground, without risking work at heights. To address these concerns we recommend removing language.

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

(b) 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~~ verifying 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 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 the first 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.

Comment on 20.2.50.116(D)(2)(a): Redline required. Notice cannot be provided each time, but we can commit to notice the first time/first use. If the department wants to observe, they can reach out and operators can accommodate that request.

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 not otherwise repaired at the time of discovery until the component has been repaired;

(2) leaks shall be repaired within ~~15~~ 30 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~~verified no later than 15 days after ~~discovery~~ repair of the leak to demonstrate that it has been repaired; ~~and~~

(4) if the leak cannot be repaired within ~~15~~ 30 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 planned process unit shutdown~~.~~ and

(5) if the leak cannot be repaired within 30 days of discovery due to shortage of parts or personnel~~-~~ , the leak may be designated "Repair delayed," and must be repaired within 15 days of resolution of such shortage.

Comment on 20.2.50.116(E)(2): Redline required because leak repair time should be consistent regardless of detection method.

Comment on 20.2.50.116(E)(3): Redline required: Verification of repair timeline should be tied to date of repair, not date of discovery.

Comment on 20.2.50.116(E)(5): Redline required due to supply chain restrictions. Below are some commentary and examples.
1. Oil and Gas companies do keep stock of some common sizes and parts for repairs and replacement. However, some fugitive emission components (or their associated parts) are not common stock and must be ordered at the time they are needed. The company is then potentially at the mercy of the distributor or manufacturer for receiving the part.
2. A valve leak was found and when maintenance went to repair, they could not. The valve was broken internally, and the valve was no longer available from the manufacturer (due to age). The piping and valve had to be re-engineered to accept a newer style/size of valve to fix the repair. This took time for Engineering to do and for Operations to implement.
3. Global Pandemic: The COVID-19 global pandemic created many stocking and manufacturing delays for parts across many sectors. Items once easily obtained became harder to source because manufacturers had reduced work.
4. 2021 Polar Vortex: The Winter storm that hit the Midwest and South in mid-February 2021 caused numerous shipping

delays and operational issues for companies in the affected areas. Many companies were working diligently to maintain normal operations in the affected area.

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~~ person(s) 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~~ tag 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;

(ii) ~~signature of the authorized representative~~ name of person(s) who determined that the repair could not be implemented without a process unit shutdown or parts and/or personnel shortages ;

(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: Manual ~~L~~liquid unloading operations ~~including down-hole well maintenance events~~ resulting in the venting of natural gas at natural gas wells are subject to the requirements of 20.2.50.117 NMAC. Manual ~~L~~liquid unloading operations that do not result in the venting of any natural gas are not subject to this part. Within two years of the effective date of this Part, owners and operators of a Natural gas well subject to this Part, must comply with the standards set forth in Paragraph (3) of Subsection B 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 venting of natural gas associated with manual liquid unloading.

(2) The owner or operator of a natural gas well shall use the following best management practices within two years of the effective date of this Part during venting associated with manual liquid unloading to minimize emissions, consistent with well site conditions and good ~~engineering~~ operating practices:

(a) reduce wellhead pressure before blowdown/venting to atmosphere;

(b) monitor manual venting associated with 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 employ methodologies to ~~use one of the following methods to~~ reduce emissions during venting associated with a liquid ~~n~~ unloading event. These methodologies may include, but are not limited to:

(a) ~~**(a)**~~ ~~installation and~~ use of a plunger lift

~~**(a)**~~**(b)** use of an automated controls system~~;~~

(~~b~~c) ~~installation and~~ use of ~~an~~ artificial lift ~~engine~~; or

(~~c~~d) ~~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, inspection or testing requirements:

(1) The owner or operator shall monitor the following parameters during venting associated with manual 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~~tank battery or atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC emitted~~vented~~ during a venting event associated with a manual liquid unloading event.

~~A venting associated with 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.~~

(3) 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 manual 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 owner or operator shall use the maximum potential flow rate in the emission calculation);

(e) duration of venting to the ~~storage vessel~~tank battery or atmosphere;

(f) a description of the management practice used to minimize venting and release of VOC emissions before and during the manual liquid unloading;

(g) the type of control device or control technique used to control VOC emissions during a venting associated with ~~the~~ a manual liquid unloading event; and

(h) a calculation of the VOC emissions vented during a venting associated with a manual ~~the~~liquid unloading event based on the duration, calculated volume, and ~~mass of VOC~~composition of the produced gas.

(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]

Comment on 20.2.50.117(A): Redline required as down-hole maintenance events (workovers) are covered in the workover portion of the proposed regulations and coverage here is redundant, will cause duplicative work, and is potentially confusing.

Comment on 20.2.50.117(B)(1): Redline required as the focus of this portion of the regulation needs to be ***venting*** *associated with liquid unloading not liquid unloading itself – i.e. managing the liquid loading in a well bore. This distinction is critical - there are a number of techniques and technologies used to manage well bore liquid loading that don't require or entail venting.*

Comment on 20.2.50.117(B)(2): Redline required to add phase in similar to other sections.

Comment on 20.2.50.117(B)(3): Redline required as there are numerous other techniques and technologies used to manage liquid loading. Velocity strings and soap/foaming agent injection are two examples. The predominant method of managing liquid loading is managing reservoir energy by use of shut-in periods to build reservoir energy and unload liquids into production rather than venting.

Comment on 20.2.50.117(C)(1)(b): Redline required as it is not feasible to measure or monitor the flow rate of vented natural gas except in a research setting. NMOGA suggests calculation techniques in the Green House Gas Reporting Rule. As support for using these, the UT 2015 research study, which measured venting, concluded that their measurements compared favorably with the calculated volumes using the GHGRP methodologies.

20.2.50.118 GLYCOL DEHYDRATORS:

A. Applicability: Glycol dehydrators with a PTE equal to or greater than two tpy of VOC and having an actual annual average flowrate of natural gas to the glycol dehydration units of greater than 3 MMscfd ~~and~~located at ~~wellhead sites~~well production facilities, 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.

Comment on 20.2.50.118.A: Redlined required to align 20.2.50.118 threshold for regulation with the threshold under 40 CFR Part 63, Subpart HH for the more stringent standards applicable to large glycol dehydration units. Imposing the emissions standards under 20.2.50.118.B to small glycol dehydration units is not warranted given the minimal emissions expected from units of this size.

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, where present, 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, where present, 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 or VRCU that reinjects the VOC emissions back into the process stream or natural gas gathering pipeline;

(b) if a VRCU is used, it shall consist of a closed loop system of seals, ducts and a compressor that reinjects the vapor~~natural gas~~ into the process or the natural gas pipeline. The VRCU 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 VRCU shall be installed, operated, and maintained according to the manufacturer's specifications;

(c) still vent and flash tank emissions shall not be vented directly to the atmosphere during normal operation; 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, inspection or testing 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. A representative gas analysis may be utilized for this calculation.

(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, inspection or testing requirements in 20.2.50.115 NMAC.

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

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, when available and applicable.

(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]

Comment on 20.2.50.118(B)(3)(c): Redline required. Under 20.2.50.118.B(3)(c), "the still vent and flash tank emissions shall not be vented to the atmosphere." At the same time, under 20.2.50.118.(B)(3)(b) a Vapor Recovery Control Unit is permitted 5% downtime. NMOGA is concerned these statements may be inconsistent in practice if the venting prohibition is applied too broadly to prohibit unavoidable releases inherent in the industry's processes. For example, common releases that will consume the 5% downtime include emissions from periods of startup or shutdown, emissions vented via air pollution control equipment to the atmosphere, or other emissions during periods of startup for certain types of air pollution control equipment (e.g., thermal oxidizers). The rule should make clear that these unavoidable releases are not prohibited under the venting prohibition.
For these reasons, NMOGA recommends the department remove the venting prohibition altogether. Alternatively, NMED should clarify the scope of the venting concept and revise the venting prohibition to only require controls during normal operations. NMOGA requests the following revision to 20.2.50.18.B(3)(c).

Comment on 20.2.50.118(B)(5): Redline required because actual emissions offramps should be based on what is actually emitted, regardless of whether those emissions are released from a controlled or uncontrolled emissions unit. Glycol dehydrators may be controlled pursuant to other legal requirements (e.g., 40 C.F.R. Part 63, Subpart HH), and operators should be authorized to take these controls into account when quantifying actual emissions for purposes of exiting 20.2.50.118 NMAC.

Comment on 20.2.50.118(C)(1): Redline required as conducting an extended gas analysis as required in 20.2.50.18.C(1) on the inlet of each glycol dehydrator increases compliance costs to the owners and operators without providing any reduction in emissions. NMED should allow representative extended analyses to be used in lieu of glycol dehydrator-specific inlet analyses. Under this approach, owners and operators would conduct a gas analysis on a representative inlet and apply this concentration to other units that, within the engineering judgment of the source, would exhibit comparable characteristics.

Comment on 20.2.50.118(D)(1)(g): Redline required because the current rule does not account for numerous scenarios where manufacturer's recommended schedules for maintenance and repair may not be available or be practical for the current operating scenario. Glycol dehydrators often have useful service lives that extend beyond a single site. As a result, the initial design and manufacturer's recommendations may not be appropriate in the new operating scenario. Additionally, documentation may not be available for older units. If this is not removed from the regulation there will be equipment that cannot meet this requirement and will continually be out of compliance with this requirement. NMED must allow owners and operators to develop maintenance and operating procedures based on site-specific factors and industry's extensive experience operating this type of equipment.

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~~well production facilities, 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~~400
Constructed or reconstructed on or after the effective date of 20.2.50 NMAC	30	~~130~~400

(2) Existing natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC no later than ~~one~~ three years 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.

C. Monitoring, inspection and testing requirements:

(1) The owner or operator shall:

(a) conduct emission testing for NOx 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 optimize the flame pattern consistent with the manufacturer specifications, if available and good ~~engineering~~ operational practices;

(iii) inspecting the AFR controller and ensuring it is calibrated and functioning properly, if such as system is installed on the heater;

(iv) optimizing total emissions of CO consistent with the NOx requirement, manufacturer specifications, if available, and good combustion ~~engineering~~ operational 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 at highest achievable load ~~within ten percent of one-hundred percent peak, or the highest achievable, load~~;

(b) determine NOX 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 NOX 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 in a prior test 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 person(s) 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]

Comment on 20.2.50.119(B)(1), Table 1: Redline required to establish a reasonable CO emission limit. NOx and CO emissions from combustion are directly correlated. As combustion temperature is increased to lower CO emissions, NOx emissions increase. Conversely as combustion temperature is decreased to lower NOx emissions, CO emissions increase. To avoid continual adjustment of temperature to control both NOx and CO, utilizing a CO well-established emission limit allows for effective control of NOx while also providing a protective limit for CO emissions. Limits from other comparative *regulations ((SCAQMD Rule 1146 & 30 TAC 117) have set a standard CO limit at 400 ppmv @ 3% O2.*

Comment on 20.2.50.119(B)(2): Redline required as more time will be needed for the large heaters at processing plants to design the change, budget for the upgraded equipment, procure the equipment and schedule the equipment downtime to minimize plant or upstream flaring events.

Comment on 20.2.50.119(C)(1)(b)(ii): Redline required in the event that manufacturer specifications are not available.

Comment on 20.2.50.119(C)(1)(b)(ii), (iv). Redlined required to change engineering to operational to reflect the fact that operational employees are generally in the best position to understand field operation of equipment.

Comment on 20.2.50.119(C)(1)(b)(iii): Redline required as some units do not have an AFR controller.

Comment on 20.2.50.119(C)(2)(a): Redline is required as heater tests should only be required to verify their emission limits at the highest achievable capacity during the test. Conditions may include insufficient fuel gas, fuel gas heat content, ambient conditions, etc. In addition, potential safety concern exists if testing team can run inlet fuel gas pressure higher (with no overpressure protection) than heater nameplate.

Comment on 20.2.50.119(C)(2)(d): Redline is required for alignment with comment above [20.2.50.119(C)(2)(a)].

Comment on 20.2.50.119(C)(4). Redlined required to align with removal of EMT requirement to scan prior to monitoring events.

20.2.50.120 HYDROCARBON LIQUID TRANSFERS:

A. Applicability: Hydrocarbon liquid transfers located at ~~wellhead sites~~well production facilities, tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations except as noted below in this section are subject to the requirements of 20.2.50.120 NMAC beginning three ~~one~~ year(s) from the effective date of this Part. ~~Hydrocarbon liquid transfer operations with a potential to emit equal to or less than 5 tpy VOC are not subject to the requirements of 20.2.50.120 NMAC.~~ Tank batteries, gathering and boosting sites, natural gas processing plants or transmission compressor stations, any of which are connected to oil sales pipelines that are routinely used for hydrocarbon liquid transfer, are not subject to the requirements of 20.2.50.120.. ~~Hydrocarbon liquid transfer operations due to pipeline downtime or associated with maintenance, start-up, or shutdown or upset issues with actual emissions less than or equal to 5 tpy VOC are not subject to the requirements of 20.2.50.120.~~ Tank batteries, gathering and boosting sites, natural gas processing plants or transmission compressor stations that load out hydrocarbon liquids to trucks fewer than thirteen (13) times in a calendar year are not subject to 20.50.2.120.

Comment on 20.2.50.120(A): Redline required to align with storage vessel requirements as retrofit of storage vessel and liquid transfer would be concurrent. This exemption will better serve the ends of the rule—to reduce VOC emissions through application of reasonably available, economically feasible controls—and will mitigate safety concerns for low flow loading occurring at liquid transfer operations. Establishing a fewer than 13 loadouts per calendar year applicability threshold and only applying this rule where oil transfers to sales through connected oil pipelines are expected except for very rare pipeline outages ensures that the stringent 98% control requirement would not be applied where minimal emissions reduction benefit will be realized. Installing such costly controls when they will be used only in emergency/upset conditions or the equivalent of once per month is economically infeasible for these smaller units from a cost-per-ton perspective. From a safety perspective, when conveying waste gas to a combustor in a low flow loading operation, the introduction of ambient air to process vessels through infiltration or forced/induced draft would create an explosion hazard. These high volumes of air introduce excess oxygen into the process or existing vapor controls for rich gas streams, creating a potentially explosive environment in the process and a risk of fire or explosion. Further, excess oxygen exacerbates corrosion and presents risks of potential loss of primary containment.

B. Emission standards:

(1) The owner or operator of a hydrocarbon liquid transfer operation shall use vapor balance or a control device designed to control VOC emissions by at least ninety-~~eight~~ five percent when transferring hydrocarbon liquid from a storage vessel to a tanker truck or tanker rail car for transport~~transfer vessel, or when transferring liquid from a transfer vessel to a storage vessel~~.

(2) ~~An owner or operator~~The personnel conducting the hydrocarbon liquid transfer operation using vapor balance ~~during a liquid transfer operation~~ shall:

(a) transfer the vapor displaced from the tanker truck or rail car ~~vessel~~ being loaded back to the storage vessel being emptied via a pipe or hose connected before the start of the transfer operation. If multiple storage vessels are vapor manifolded together in a tank battery, then the vapor may be routed back to any storage vessel in the tank battery;

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

(c) ~~ensure that~~inspect connector pipes, hoses, couplers, valves, and pressure relief devices for leaks;

~~are maintained in a leak-free condition;~~

(d) check the hydrocarbon 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 inspected for leaks~~maintained in a leak-free condition~~.

(5) Connections of hoses and pipes used during hydrocarbon 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~~ minimizes 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.

Comment on 20.2.50.120(B)(1): The proposed 98% destruction efficiency and controls are more stringent than similar provisions promulgated in nonattainment areas or under more stringent control technology standards and cannot be achieved on a continuous basis. For example, the FIP for the Uintah Basin ozone nonattainment area did not impose a control efficiency requirement and merely stipulated that tank trucks must be loaded using bottom filling or a submerged fill pipe. 85 Fed. Reg. at 3532. Similarly, Utah conducted a "Best Available Control Technology" review for tank truck loading of hydrocarbon liquids and only imposed a 95% VOC destruction efficiency and a bottom filling or a submerged fill pipe requirement. U.A.C. R307-504-4.

NMOGA also believes the requested revisions are reasonable because they are consistent with design requirements for other equipment subject to this rule. For example, NMED has determined that 95% control is appropriate for storage tanks with a potential to emit between 2-10 TPY, an emissions range that is consistent with the potential emissions of many hydrocarbon liquid transfer operations. Hydrocarbon liquid transfers may be required during infrequent, non-routine operating scenarios. For example, LACT downtime may lead to emergency hydrocarbon liquid transfers. Similarly, hydrocarbon liquid transfers may be required during infrequent condensate loads at compressor stations where flares may not otherwise be present. In these scenarios, adding a vent to combustion or vapor balance is not cost effective. NMOGA requests that such operations be exempted from the control requirements in 20.2.50.20.B or that NMED set an appropriate threshold for applicability. Vapor recovery would introduce oxygen to the product stream and potentially not meet sales specifications. This would require shut-ins or flaring, ultimately creating emission events. Adding bottom loading or submerged filling allows for additional options to meet the emissions reductions.

NMOGA has also clarified that the 95% control efficiency requirement should be based on control device design. This change is made to ensure consistency with section 20.2.50.115.B.2, which requires that control devices be "adequately designed and sized to achieve the control efficiency rates required."

Comment on 20.2.50.120(B)(2)(a): Redline required for when multiple tank vapor spaces are manifolded and adequately communicating vapor space, vapor may be returned to any one of the tanks or to the vapor header.

Comment on 20.2.50.120(B)(3): If control with control device or vapor balance maintains the 95%, this adds no additional value.

Comment on 20.2.50.120(B)(6): Redline required as it is impossible to clean up a leak in a manner that prevents all emissions to the atmosphere. By definition, a leak means that the liquid is exposed to atmosphere and will volatilize.

C. Monitoring requirements:

(1) The owner or operator or their designated representative shall visually inspect the hydrocarbon liquid transfer equipment monthly at staffed locations or semiannually for unstaffed locations ~~during a transfer operation~~ to ensure that hydrocarbon 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 or proper measures must be implemented to mitigate leaks until the necessary repairs can be completed.

(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 H2O (inches H2O)	Allowable pressure change (Δp) in five minutes, mm H2O (inches H2O)
< 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.

Comment on 20.2.50.120(C)(1): Redline required as monitoring requirements in C(1) are redundant with AVO provisions in 20.2.50.116C(2)(a). Further, C(1) implies that inspections must occur during every loading event. However, this is not practicable as some facilities may not be staffed during all hydrocarbon liquid transfer operations. If it is NMED's intent to require inspections during loading events, NMOGA requests that a more reasonable inspection frequency be established. NMOGA believes a monthly visual inspection for staffed locations and a semiannual visual inspection for unstaffed locations would be appropriate. While NMOGA members can take measures to prevent leaks from reoccurring, a permanent fix may not be feasible or realistic before the next transfer operations. However, NMOGA members may be able to implement certain measures to mitigate the leaks until a permanent fix can be implemented.

Comment on 20.2.50.120(C)(2): Consistent with the General Comments, NMOGA has concerns about manufacturer specifications. While operators strive to establish appropriate operating, maintenance, and repair procedures, we may learn through our unique operating experience with the equipment that something different than the manufacturer's specifications should be followed. Furthermore, small details in manufacturer's specifications should not be enforceable regulatory requirements. If this provision is retained, NMOGA requests that it be given flexibility to revise these specifications based on its experience with the equipment.

Comment on 20.2.50.120(C)(3): These requirements impose testing requirements on pieces of equipment (i.e. tank trucks) that are not owned or operated by upstream oil and gas producers and are not stationary sources. While NMOGA would support a vapor tightness recordkeeping requirement, it is not appropriate to impose vapor tightness performance standards on oil and gas operators who do not own or operate these pieces of equipment. NMED is also preempted from imposing these standards under 49 U.S.C. § 5125(b) and 49 U.S.C. § 10501(b).

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~~1) The owner or operator shall maintain a record of the inspections and testing required for equipment they own and operate in Subsection C of 20.2.50.120 NMAC and shall include the following:

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

(b) the name of the ~~personnel~~ person(s) 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~~

(~~4~~2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

Comment on 20.2.50.120(D)(1): Redline required as it is duplicative with storage tank requirements. Redline required as NMED has yet to provide any cost benefit information regarding the estimated reduction in ozone precursors that will be gained by implementing this part.

Comment on 20.2.50.120(D)(2): Redline required as owners and operators should not be required to maintain records of testing conducted on equipment they do not own or operate.

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

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

20.2.50.121 PIG LAUNCHING AND RECEIVING:

Comment on 20.2.50.121. NMOGA requests removal of the proposed pig launching and receiving provisions. NMOGA does not believe these standards are justified considering the minimal emissions reductions predicted and the technological and economic feasibility issues anticipated. Illustratively, EPA's Control Techniques Guideline (CTG) evaluation does not recommend standards for pig launching and receiving. In explaining the sources selected for EPA's 2016 review, the agency explained, "[t]hese sources were selected for RACT recommendations because current information indicates that they are significant sources of VOC emissions." NMOGA concurs with EPA that pig launching and receiving are not generally significant sources of VOC emissions and imposition of controls is not warranted. Although the CTG review took place in 2016, the emissions profile for these sources has not changed, and NMED's analysis does not justify a conclusion different than the one reached by EPA. In fact, according to NMED's own data supporting this rule, VOC emissions from pig launching and receiving are a scant 0.2 TPY, and VOC emissions will not be reduced as a result of the rule. While this analysis is questionable, it does not support the controls proposed. And although there has been an enforcement focus on pig launching and receiving from EPA, the alleged violations have largely focused on operators' failure to properly account for pig launching and receiving in their permitting activities. This focus does not reflect a revised belief that controlling pig launching and receiving is necessary to reduce ozone concentrations, as NMED's rule is intended to do. What is more telling is EPA's 2020 federal implementation plan proposal for the Uintah Basin nonattainment area, 85 Fed. Reg. 3492 (Jan. 21, 2020), in which EPA did not propose any standards for pig launching and receiving. This stance is consistent with EPA's 2016 CTG and NMED's own analysis. Finally, although controls on pig launching and receiving have been implemented in limited contexts in other areas of the country, NMED has not fully vetted the challenges for implementing these approaches in a state like New Mexico where sites are remote and lack infrastructure. For example, NMED has not evaluated whether requiring control of remote pigging operations would have a negative net effect on ozone concentrations because of NOx emissions from the additional transport of personnel and equipment. While NMOGA urges NMED to remove these provisions, if NMED elects to retain them, NMOGA has several suggestions for improvement.

A. **Applicability**: Individual p~~P~~ipeline pig launchers~~ing~~ and/or receivers ~~ing operations~~ with a PTE greater than or equal to one tpy VOC located within ~~or outside of~~ the property boundary of ~~wellhead sites~~well production facilities, 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.

Comment on 20.2.50.121(A): Redline required to eliminate applicability to off-facility pigging operations and operations with potential emissions less than 1 TPY. Pigging is a small source of VOCs. Since NMED's model shows that ozone is NOx limited, controlling pig traps with NOx-producing combustion will not have the desired ozone impact. This is particularly true where the emissions potential from the operation is minimal or pigging takes place outside facility locations, a process that requires additional generation of NOx from the use of portable flares and trucks for transporting controls and personnel.

B. Emission standards:

(1) Owners and operators of affected pipeline pig launch~~ersing and~~ or receiv~~ersing operations with a PTE equal to or greater than one tpy of VOC~~ shall capture and reduce VOC emissions from pigging operations by at least ninety-~~eight~~ five percent ~~,~~within 3 years of ~~beginning on~~ the effective date of this Part.

(2) The owner or operator conducting an affected ~~the~~ pig launching and/or receiving operation shall:

(a) employ best management practices to minimize the liquid present in the pig receiver chamber and to minimize~~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~~ minimize 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~~ minimizes emissions to the atmosphere to the extent practicable; 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 an individual pipeline pig launcher and/or receiver if the uncontrolled actual annual VOC emissions of the ~~operation~~ launcher or receiver are less than one 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.

Comment on 20.2.50.121(B)(2)(c): Redline required because, while NMOGA agrees that emissions can be minimized through proper recovery of receiver liquids, fugitive emissions that are impractical to prevent will occur.

Comment on 20.2.50.121(B)(3): Redlined required to clarify that the 1 TPY threshold should be calculated based on the emissions potential of a single pig launcher or receiver.

C. Monitoring, testing and inspection requirements:

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

(~~2~~1) The owner or operator of an affected pig launching and receiving ~~operations~~ site shall inspect the equipment for ~~a~~ leaks using either AVO, RM 21, or OGI on either:

(a) a monthly basis if pigging operations at a site occur on a monthly basis or more frequently; or

(b) prior to the commencement and ~~immediately before the commencement and immediately~~ after the conclusion of the pig launching or receiving operation, if less frequent.

(2) The monitoring procedures shall be performed using the methodologies outlined ~~in accordance with the requirements~~ in Paragraphs (2) through (4)) of Subsection (C) of 20.2.50.116 NMAC as applicable, and at the frequency outlined in Paragraph (1) of Subsection (C) of 20.2.50.121. The monitoring shall be performed when the pig trap is under pressure.~~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 non-portable control device shall comply with the monitoring requirements in 20.2.50.115 NMAC. A portable control device is not subject to the monitoring requirements of 20.2.115 NMAC and shall be designed for a ninety-five percent control efficiency.

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

Comment on 20.2.50.121(C)(1): Redline required as this has no bearing on emissions from receivers and should be removed.

Comment on 20.2.50.121(C)(2): Redline required to add AVO as an option. Reduces monitoring frequency to no more than once per month and for pigging operations that occur less frequently than monthly, monitoring is performed on a per pigging event basis. Redline added to allow monitoring during representative conditions rather than associated with launching or receiving a pig.

D. Recordkeeping requirements:

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

(a) the pigging operation, including the location and 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.

(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:

NMOGA Comment on 20.2.50.122. Emission Factors for intermittent controllers are incorrect in ERG study, and costs associated with modifications are understated. Cost per ton of VOC in ERG reports is significantly understated. Reference "Valor Memo - Pneumatic Controllers 20.2.50.122" and "Valor Memo - Pneumatic Controllers 20.2.50.122 Emission Factors." NMOGA supports moving away from pneumatic controllers, unless justified as necessary for safety or process control, in an orderly fashion and proposes an approach that does so consistent with parts availability, labor requirements and the sheer number of controllers to be addressed at substantially less cost.

A. Applicability: Natural gas-driven pneumatic controllers and diaphragm pumps permanently located at ~~wellhead sites~~well production facilities, tank batteries, gathering and boosting sites and~~,~~ natural gas processing plants~~, and transmission compressor stations~~ ~~are~~stations are subject to the requirements of 20.2.50.122 NMAC, except for pumps that operate less than 90 days per calendar year.

NMOGA Comment on 20.2.50.122.A:
The changes proposed to reflect definitional changes for greater clarity and to align with NSPS Subpart OOOOa for temporary and sump pumps. Alignment, where possible, reduces confusion and facilitates compliance.

B. Emission standards:

(1) A new ~~wellhead site~~well production facility, tank battery, gathering and boosting site, and natural gas processing plant~~, or transmission compressor station~~ ~~natural gas-driven pneumatic controller or pump~~ shall comply with the requirements of 20.2.50.122 NMAC upon startup.

(2) New well production facilities, tank batteries, gathering and boosting sites, and natural gas processing plans shall have Non-Emitting Controllers installed except as allowed in Paragraph (5) of Subsection B of 20.2.50.122 NMAC. ~~An existing natural gas-driven pneumatic diaphragm pump shall comply with the requirements of 20.2.50.122 NMAC within three years of the effective date of this Part.~~

(3) ~~Wellhead sites~~Well production facilities and their associated ~~,~~tank batteries,~~, gathering and boosting facilities, natural gas processing plants, or transmission compressor stations An existing natural gas-driven pneumatic controller~~in existence on the effective date of Part 50 ("pre-effective date") shall comply with the requirements of 20.2.50.122 NMAC according to the ~~following schedule~~schedules ~~outlined~~orth in Tables 1 ~~and 2~~ below ~~as applicable~~:

Table 1 – ~~WELLHEAD SITES~~WELL PRODUCTION FACILITIES AND ASSOCIATED~~,~~ TANK BATTERIES~~, GATHERING AND BOOSTING FACILITIES~~

Total Historic ~~Percentage of~~ Non-Emitting Facility Percent Production~~Controllers~~	Total Required ~~Percentage of~~ Non-Emitting Facility Percent Production~~Controllers~~ by January 1, 2024	Total Required ~~Percentage of~~ Non-Emitting Facility Percent Production~~Controllers~~ by January 1, 2027	Total Required ~~Percentage of~~ Non-Emitting Facility Percent Production~~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%

(a) For purposes of this section, a "Non-Emitting Facility" means a facility with only Non-Emitting Controller except as allowed under Paragraph (5) or (7) of Subsection B of 20.2.50.122 NMAC.

(b) Except as provided in 20.2.50.122.B.(3)(c) or (d), owners or operators of pre-efffective date well production facilities and associated tank batteries shall by January 1, 2023:

(i) Determine the Historic Facility Production for each pre-effective date well production facility by summing the total liquids productions (summing total barrels of oil and water produced through the well production facility) for the calendar year 2020. For a well production facility that does not have a full calendar year of data, then the owner or operator may use 2021 data or an estimate of the anticipated yearly production for the facility based on industry accepted calculation methodologies.

(ii) Calculate the Total Historic Production for the owner or operator by summing the Historic Facility Production for all pre-effective date well production facilities.

(iii) Calculate the Facility Percent Production for each existing facility by dividing the Historic Facility Production by the Total Historic Production.

(iv) Determine the Total Historic Non-Emitting Facility Percent Production by summing the Facility Percent Production for each Non-Emitting Facility as defined in Subparagraph (5)(a) of Subsection B of 20.2.50.122 NMAC. The Total Historic Non-Emitting Facility Percent Production determines an owner or operator's January 1, 2024, January 1, 2027 and January 1, 2030 Total Required Non-Emitting Facility Percent Production as set forth in Table 1, except as provided in subparagraphs (c) or (d) of this Paragraph (3).

(v) Owners and operators must demonstrate compliance with Table 1's January 1, 2024, January 1, 2027 and January 1, 2030 Total Required Non-Emitting Facility Percent Production through any combination of retrofitting pre-effective date well production facilities (and associated tank batteries) to use non-emitting controllers or plugging and abandoning an such well production facility and emptying and decommissioning an associated tank battery. A tank battery that is decommissioned and moved to another location is a new facility for purposes of 20.2.50.122.B.(1) and (2) NMAC.

(c) In lieu of the demonstration required by 20.2.50.122.B.(3)(b) NMAC, an owner or operator may demonstrate that its total oil and natural gas production subject to Part 50 averages fifteen barrels of oil equivalent~~(using a 6 mcf to 1 barrel oil equivalent for natural gas)~~ or less per well per day annual average. To calculate total oil and natural gas production subject to Part 50, an owner or operator must sum all affected oil and natural gas production in calendar year 2020 in barrels of oil equivalent, divide by 365, and divide by the number of affected wells producing hydrocarbons that the owner or operator operated in 2020.

(d) If an owner or operator meets at least seventy-five percent Total Non-Emitting Facility Percent Production by January 1, 2025, table 1 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC does not apply and the owner or operator shall maintain the Total Non-Emitting Facility Percent Production at seventy-five percent or greater thereafter.

(e) High Bleed Controllers shall be retrofitted or replaced no later than January 1, 2024 unless allowed under Paragraph (5) of Subsection B of 20.2.50.122 NMAC.

(4) Pneumatic controllers at gathering and boosting sites and natural gas processing plants existing as of the effective date ("pre-effective date") shall meet the required percentage of non-emitting controllers according to the schedule outlined in Table 2 below:

Table 2 – ~~NATURAL GAS COMPRESSOR STATIONS~~GATHERING AND BOOSTING SITES 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%

~~**(4)** Standards for natural gas-driven pneumatic controllers.~~

(a) ~~for new all controllers installed at facilities that commence construction after the effective date of this Part new pneumatic controllers shall use non-emitting controllers except natural gas-drive pneumatic controllers shall be allowed for a safety or process purpose that cannot otherwise be met without emitting natural gas shall have a~~ natural gas ~~emission rate of zero.~~

~~(b) existing pneumatic controllers with access to commercial line electrical power shall have an emission rate of zero.~~

(~~c~~b) ~~existing pneumatic controllers at existing facilities~~ Pre-effective date gathering and boosting sites and natural gas processing plants shall phase out natural gas driven pneumatic controller to meet the required percentage of non-emitting controllers within the deadlines in table~~s 1 and~~ 2 of Paragraph (4~~3~~) of Subsection B of 20.2.50.122

NMAC, and shall comply with the following, except as provided in Paragraph (5) of Subsection B of 20.2.50.122 NMAC:

(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~~ pre-effective date gathering and boosting stations and natural gas processing plants subject to Part 50 ~~that commenced construction before the effective date of this Part~~. The total controller count must include all emitting natural gas-driven pneumatic controllers and all non-emitting ~~pneumatic~~ controllers of any type (e.g. mechanical, electric, instrument air-driven, natural gas-driven routed to a combustion device, etc), except that natural gas-driven pneumatic controllers ~~necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas~~ allowed under Paragraph (5) of Subsection B of 20.2.50.122 NMAC 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 table~~s~~ ~~1 and~~ 2 of Paragraph (4~~3~~) of Subsection B of 20.2.50.122 NMAC applies~~y~~ and the retrofit ~~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 (4~~3~~) of Subsection B of 20.2.50.122 NMAC do not apply

(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.

(b) High Bleed Controllers shall be retrofitted or replaced no later than January 1, 2024 unless allowed under Paragraph (5) of Subsection B of 20.2.50.122 NMAC.

(5~~de~~) ~~a natural gas-driven pneumatic controller with a continuous bleed rate greater than six standard cubic feet per hour 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 install an emitting natural gas-driven pneumatic controller at a new facility maintain operation of an emitting pneumatic controller must prepare and document the justification for the safety or 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 in-house or professional engineer.~~Pneumatic controllers that emit natural gas to the atmosphere meeting any of the following conditions are not subject to the requirements of Paragraphs (2), (3) or (4) of Subsection B and are not required to be retrofit to count the facility or controller as non-emitting for compliance with Tables 1 and 2 of Subsection B of 20.2.50.122 NMAC.

(a) A natural gas pneumatic controller at a new well production facility, tank battery, gathering and boosting site, or natural gas processing plant or a pre-effective date well production facility and its associated tank batteries classified as a Non-Emitting Facility ~~with a bleed rate greater than six standard cubic feet per 10 hour~~ is permitted when the owner or operator has demonstrated that ~~a higher bleed rate~~it 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 at a new or Non-Emitting Facility must prepare and document the justification for the safety or process purposes prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be certified by qualified maintenance or engineering staff ~~a qualified professional engineer~~.

(b) Pneumatic controllers that emit natural gas located or temporary or portable equipment that is used for well abandonment activities or used prior to or through the end of flowback.

(c) Pneumatic controllers that emit natural gas located on temporary or portable equipment that is on-site and in-use for 90 days or less.

(d) Pneumatic controllers in an automated control system installed to comply with Paragraph (3)(b) of Subsection B of 20.2.50.117 NMAC.

(6~~5~~) Standards for natural gas-driven pneumatic diaphragm pumps.

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

(b) new pneumatic diaphragm pumps located at a ~~wellhead sites~~well production facilities, tank batteries, gathering and boosting sites, or transmission compressor stations with access to commercial line electrical power shall have a natural gas emission rate of zero.

(c) **existing** pneumatic diaphragm pumps located at a natural gas processing plants shall have a designed natural gas emission rate of zero within 3 years of the effective date of this rule.

(d) **existing** pneumatic diaphragm pumps located at a well production facilities, storage vessels, gathering and boosting sites, or transmission compressor stations with access to commercial line electrical power shall have a natural gas emission rate of zero within 3 years of the effective date of this rule.

(~~e~~e) ~~owners and operators of~~ Existing pneumatic diaphram pumps located at ~~wellhead sites~~well production facilities, tank batteries, or gathering and boosting sites~~, or transmission compressor stations~~ without access to commercial line electrical power shall reduce VOC emissions from the natural gas-driven pneumatic diaphragm pumps by ninety-five percent if it is technically feasible to route emissions to an existing 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. The rerouting or control device installation must be accomplished within three years.

(7) If after January 1, 2027, an owner or operator's remaining natural gas pneumatic controllers, or if two years after the effective date, an owners or operator's existing natural gas pneumatic diaphragm pumps at a site without commercial line power, 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.

~~**(6)** 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.~~

NMOGA Comments on 20.2.50.122.B:
(1) No "new" pneumatic controllers. NMOGA supports no new natural gas driven pneumatic controllers except in those cases where they are required and justified for safety or specific operational reasons, as recognized in the NM OCD rule, or where there is no technically feasible alternative as approved by the department.
(2) Facility versus controller focus for compliance demonstration. The most common replacement for pneumatic controllers is substitution of instrument air or line or generator-powered electrical controllers. In making such replacements, it is generally not feasible to replace a single pneumatic controller because of the cost of the supporting infrastructure (compressors, generators, transformers, solar panels, etc.), particularly for upstream facilities. Accordingly, for well production facilities and their associated tank batteries, planning at the facility level allows for orderly replacement rather than ad hoc replacement, which is more certain to achieve the desired reductions and will reduce costs.
(2) Well production facilities and associated tank batteries. NMOGA recommends the approach taken in Colorado where production throughput, which correlates to controller releases, is used to plan and track reductions in controllers. This approach determines whether a well production facility and its associated tank batteries are a "Non-Emitting Facility" meaning that all controllers are non-emitting ones unless specifically justified. The percent of historic production passing through Non-Emitting Facilities is then calculated and the owner and operator comply with the required reductions by showing that well production facilities and their associated tank batteries are retrofitted with non-emitting controllers or retired. The proposed redline reflects this change to a production basis. The production basis is easier to track and monitor for compliance than the individual controller basis because the entire facility will use non-emitting controllers (except as allowed under paragraph (5)). Simplicity and clarity will enhance compliance.
(3) Gathering and boosting sites and natural gas processing plants. These facilities are more complex and lend themselves to the controller count approach proposed by NMED and also used in Colorado. Any type of non-emitting controller should be satisfactory to demonstrate compliance, including but not limited to routed pneumatic controllers (e.g.,, those whose exhaust is routed to a process or control device).
(4) NMOGA supports the "early compliance alternative." NMED has proposed to allow facilities that achieve 75% non-emitting controllers (now 75% of affected production through "Non-Emitting Facilities" under NMOGA's proposal) by January 1, 2025 to stop at 75%. NMOGA supports this plan but believes it should be available to any operator and should not exclude proactive operators who have already achieved the 75% threshold.

C. Monitoring, testing, or inspection requirements:

(1) Pneumatic controllers or diaphragm pumps not using natural gas or other hydrocarbon gas as motive force ~~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 facility with one or more natural gas-driven pneumatic controllers subject to the deadlines set forth in ~~tables~~ Tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each subject pneumatic controller at each facility.

(3) The owner or operator of a natural gas-driven pneumatic controller ~~with a designed bleed rate greater than zero~~ shall, on a monthly basis, ~~scan the controller and~~ conduct an AVO or OGI 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~~ on the natural gas-driven pneumatic controller according to manufacturer specifications to ensure that the VOC emissions are minimized.

(4) For any natural gas-driven pneumatic controller remaining in operation after January 1, 2030, the owner or operator shall maintain an inventory containing the following:~~The EMT shall be linked to a database that contains the following~~:

(a) natural gas-driven 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.~~

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

(6) The owner or operator shall monitor the oil and gas and liquid production through each well production facility and any associated tank batteries in calendar year 2020, or of the method used to calculate production if a full year of data are not available for calendar year 2020 as set forth in Paragraph (3)(b) of Subsection B of 20.2.50.112 NMAC.

(7~~6~~) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

NMOGA comments on 20.2.50.122.C
The proposed changes implement the recommendations made for subsection B. The change to C.(1) clarifies that monitoring does not apply to instrument air or other controllers that don't use natural gas or other hydrocarbon gas. This means that routed controllers are still subject to AVO requirements. Other changes allow OGI inspections in addition to AVO and set inventory requirements for any natural gas pneumatic controllers that will remain in place after the phase out.

D. Recordkeeping requirements:

(1) **Non-emitting** ~~Pneumatic~~ controllers and pumps ~~with a natural gas designed 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 each pre-effective date well production facility and associated tank battery, its calendar year 2020 total liquids production, the calendar year 2020 total oil and gas production at all existing well production facilities subject to Part 50, whether the well production facility and associated tank battery was a Non-Emitting Facility in 2020 and its status in the current calendar year, and the 2020 liquid throughput for each well production facility and associated tank battery. An owner an operator complying with Table 1 of Paragraph (3) of Subsection B shall, beginning in calendar year 2022 each year through calendar year 2031, calculate its Non-Emitting Facility Percent Production as set forth in Paragraph (3)(b) of Subsection B except substituting the reporting year's Non-Emitting Facilities multiplied by the 2020 Facility Percent Production in the numerator and dividing by the owner or operator's 2020 Total Historic Production in the denominator.

(3) The owner or operator of existing well production facilities complying with the limitation on daily average per well production set forth in Paragraph (3)(c) of Subsection B shall keep its calculation of its daily average production as required under Paragraph (3)© of Subsection B of 20.2.50.122 NMAC..

(4) The owner or operator shall maintain a record for each pre-effective date gathering and boosting site and natural gas plant 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~~of all emitting and N~~n~~on-E~~e~~mitting ~~pneumatic~~ C~~c~~ontrollers. An owner an operator complying with Table 2 of Paragraph (3) of Subsection B shall, beginning in calendar year 2022 each year through calendar year 2031, calculate its Percentage of Non-Emitting Controllers as set forth in Paragraph (4) of Subsection B except substituting the calendar year's count of Non-Emitting Controllers in the numerator and retaining the 2020 count of total controllers in the denominator.

(5~~3~~) The owner or operator shall maintain a record of the total count of natural gas-driven pneumatic controllers allowed under Paragraphs (5) or (7) of Subsection B of 20.2.50.122 ~~necessary for a safety or process purpose that cannot otherwise be met without emitting VOC~~.

(6~~4~~) The owner or operator of a natural gas-driven pneumatic controller subject to the requirements in ~~tables~~ Tables 1 and 2 of Paragraphs (3) and (4) ~~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.~~set forth therein.

(7~~5~~) The owner or operator shall maintain an electronic record for each natural gas pneumatic controller ~~with a natural gas designed bleed rate greater than zero~~. The record shall include the following:

(a) pneumatic controller identification number;

(b) inspection dates;

(c) name of the ~~personnel~~ person(s) conducting the inspection;

(d) AVO or OGI inspection result;

(e) ~~AVO or OGI 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.

(8~~6~~) The owner or operator of a natural gas-driven pneumatic controller ~~with a design bleed rate greater than six standard cubic feet per hour~~ allowed under Paragraphs (5) or (7) of subsection B of 20.2.50.122 shall maintain a record ~~in the EMT database~~ of the pneumatic controller documenting ~~why a bleed rate greater than six scf/hr is necessary~~the justification, as required in Subsection B of 20.2.50.122 NMAC.

(9~~7~~) The owner or operator shall maintain a record ~~in the EMT database~~ for a natural gas-driven pneumatic diaphram 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 diaphragm 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 in-house employee or professional engineer that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

(10~~8~~) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

(11) The owner or operator of a pre-effective date facility subject to Table 1 or Table 2 of Subsection B of 20.2.50.122 NMAC must retain records of its calculations until two years after compliance with the January 1, 2030 requirement in Table 1 or Table 2, as applicable, is achieved and reported to the department.

NMOGA comments on 20.2.50.122.D
Change to D.(1) reflects new terminology.
New D.(2) provides recordkeeping to calculate required percent production reduction and progress toward the phase out goals set in Table 1 for well production facilities and their associated tank batteries.
New D.(3) requires that an owner or operator complying with the paragraph B.(3)(c) (less than 15 barrels of oil equivalent per day) alternative must keep the demonstration of compliance required by that paragraph.
New D.(4) provides recordkeeping to calculate the required reduction in the percent of pneumatic controllers at gathering and boosting sites and natural gas processing plants.
New D.(11) states how long these records must be kept after the phase down is complete.

E. Reporting requirements:

(1) An owner or operator with pre-effective date well production facilities and associated tank batteries complying with Subparagraph (b) or (d) of Paragraph (3) of Subsection B shall submit a Well Production Facility/Tank Battery Pneumatic Controller Compliance Plan on a Department-approved form by January 1, 2023 including:

(a) For each pre-effective date well production facility and associated tank battery, the Historic Facility Production, Facility Percent Production, both calculated in accordance with Paragraph (3) of Subsection B, whether the facility is a Non-Emitting Facility, and the API number for each well production facility.

(b) The Total Historic Production, Total Historic Non-Emitting Facility Percent Production, both calculated in accordance with Paragraph (3) of Subsection B, and the schedule of Total Required Non-Emitting Facility Percent Production applicable to the owner and operator pursuant to Table 1 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.

(c) The planned schedule developed under Paragraph (5) of Subsection D of 20.2.50.122 NMAC.

(2) An owner or operator with pre-effective date well production facilities and associated tank batteries complying with Subparagraph (c) of Paragraph (3) of Subsection B shall submit a Low Production Well Declaration on a Department approved form by January 1, 2023 including:

(a) A statement of the 2020 hydrocarbon production for each existing well production facility by API number, in barrels of oil equivalent.

(b) A summation of the 2020 total hydrocarbon production in barrels of oil equivalent from all existing well production facilities subject to Part 50, with this sum divided by 365 and showing that the 2020 annual average production was less than 15 barrels of oil equivalent.

(3) An owner or operator with pre-effective date gathering and boosting sites or natural gas processing plants shall submit a Gathering and Boosting Site/Natural Gas Processing Plant Pneumatic Controller Compliance Plan on a

Department-approved form by January 1, 2024 including:

(a) For each pre-effective date gathering and boosting site or natural gas processing plant, the total count of controllers at that site or plant, including the count of pneumatic controllers, non-emitting controllers, and controllers allowed under Paragraph (5) of Subsection B.

(b) For all pre-effective date gathering and boosting sites or natural gas processing plants subject to Part 50 operated or owned, the total count of controllers, including the count of pneumatic controllers, non-emitting controller, and controllers allowed under Paragraph (5) of Subsection B, and the schedule of Total Historic Non-Emitting Controller Percentage applicable to the owner and operator pursuant to Table 2 of Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

(c) The planned schedule developed under Paragraph (5) of Subsection D of 20.2.50.122 NMAC.

(4) Each year beginning on July 1, 2023 and continuing until compliance with Table 1 of Subsection B is achieved, an owner and operator with pre-effective date well production facilities and associated tank batteries subject to Table 1 of Subsection B shall submit an Annual Well Production Facility/Tank Battery Pneumatic Compliance Report for the prior calendar year on a department approved form. The report shall:

(a) Identify the owner and operator and the year for which the report is submitted.

(b) Identify the number of well production facilities (including associated tank batteries) that were retrofitted to become Non-Emitting Facilities, well production facilities and associated tank batteries that were plugged and abandoned and the tank battery decommissioned, including the month of plugging and/or decommissioning.

(c) A calculation of the Non-Emitting Facility Percent Production calculated for the prior calendar year using the procedures in Paragraph (2) of Subsection D of 20.2.50.122 NMAC and a comparison to the currently applicable standard in Table 1.

(d) A revised Well Production Facility/Tank Battery Pneumatic Controller Compliance Plan as set forth in Paragraph (5) of Subsection D if the Total Required Non-Emitting Facility Percent Production required by Table 1 has not been met.

(5) Each year beginning on July 1, 2023 and continuing until compliance with Table 2 of Subsection B is achieved, an owner and operator of pre-effective date gathering and boosting sites or natural gas production plants subject to Table 2 of Subsection B shall submit an Annual Gathering and Boosting Site/Natural Gas Production Plant Pneumatic Compliance Report for the prior calendar year on a department approved form. The report shall include:

(a) Identify the owner and operator and the year for which the report is submitted.

(b) Identify the number of natural gas driven pneumatic controllers that were retrofitted to non-emitting controllers, or that were decommissioned, including the month of plugging or decommissioning.

(c) A calculation of the Percent Non-Emitting Controllers calculated for the prior calendar year using the procedures in Paragraph (3) of Subsection D of 20.2.50.122 NMAC and a comparison to the currently applicable standard in Table 2.

(d) A revised Gathering and Boosting Site/Natural Gas Processing Plant Pneumatic Compliance Plan as set forth in Paragraph (5) of Subsection D if the Total Required Percent Non-Emitting Controllers required by Table 2 has not been met.

(e) 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]

NMOGA comments on 20.2.50.122.E
New E.(1)-(3) reports. These paragraphs require an initial report to the department by January 1, 2023 of the applicable standards and schedules for each owners or operator's pre-effective date facilities. This provides the department with assurance that each owner/operator has a compliance plan and schedule in place to meets its obligations under Subsection B.
New E.(4)-(5) reports. These paragraphs require an annual report showing each owner and operator's progress toward compliance with the schedules under Tables 1 or 2 for pre-effective date facilities. The annual report provides added assurance to the department that the obligations of Tables 1 and 2 will be met.

20.2.50.123 STORAGE VESSELS

A. Applicability: Existing single storage vessel and existing multiple storage vessel tank batteries where individual tank uncontrolled PTE is equal to or greater than six tpy of VOC, and new single storage vessel and new multiple storage vessel tank batteries where individual tank uncontrolled PTE is equal to or greater than two tpy of VOC, located at. ~~Storage vessel(s) with an uncontrolled PTE equal to or greater than two tpy of VOC and located at wellhead sites~~tank batteries located at well production facilities, ~~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. In determining the individual tank uncontrolled PTE, owners or operators will use generally accepted methods for estimating emissions. Where multiple storage vessels are manifolded together with piping such that all vapors are shared between the headspace of the storage vessels and are routed to a common outlet or end point, owners or operators may determine individual storage vessel emissions by averaging the emissions across the total number of storage vessels in the tank battery. The requirements of 20.2.50.123 NMAC do not apply to storage vessels subject to the requirements for storage vessels in 40 CFR part 60, subpart Kb, OOOO, and OOOOa, and 40 CFR part 63, subparts G, CC, HH, or WW.

Comment on 20.2.50.123(A): Redline required to align with proposed changes per the Valor Memo - Storage Vessels 20.2.50.123. Redline regarding averaging emissions across manifolded tank batteries is required to provide a reasonable methodology for determining potential emissions and rule applicability for such configurations. Where multiple manifolded storage vessels share headspace and are routed to a common end point, emissions from each respective tank are indistinguishable from one another. Where such configurations are routed to and controlled by a common control device, emissions from all tanks achieve the same destruction efficiency. Consequently, determining emissions for each respective tank by averaging the potential emissions rate across the number of units in the battery is an appropriate measure of each unit's potential emissions. Where the average VOC emissions across the number of storage vessels in the controlled battery is equal to or greater than the applicability threshold, all of the storage vessels in the controlled battery are subject to the standard. However, where the average emissions are less than the applicability threshold, none of the storage vessels in the controlled battery are subject to the standard. This is the approach EPA has taken for determining applicability under 40 C.F.R. Part 60, Subpart OOOOa. See 85 Fed. Reg. 57398, 57411 (Sept. 15, 2020).

B. Emission standards:

(1) An existing storage vessel with a PTE equal to or greater than ~~two~~ six 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-eith 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 for new tanks and four tpy for existing tanks.

(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 by shutting in or reducing production from the well supplying the storage vessel by the applicable date such that the uncontrolled annual emissions are less than two tpy for new tanks and four tpy for existing tanks, and not resuming or increasing production from the well until the control device is installed and operational or the Department has approved an extension of the deadline.

(7) The owner or operator of a new or existing storage vessel with a thief hatch ~~shall install a control device that allows the~~ shall ensure that the thief hatch is capable of ~~to~~ opening sufficiently to relieve overpressure in the vessel and to automatically close once the vessel overpressure is relieved. Owners and operators may also install other pressure relief devices to ensure that overpressure can be adequately relieved. Any pressure relief device installed must 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 15 20.2.50.115 NMAC.

Comment on 20.2.50.123(B)(2), (4): Redline required as this effectively prohibits the use of thief hatches. If we assume that the control device has 98% destruction efficiency you would need to have 100% capture to meet this requirement. There is 0% capture any time a hatch is open and hence hatches are effectively being banned by this requirement.

Comment on 20.2.50.123(B)(7): Redline required as there is no such thing as a control device that allows a thief hatch to open. Furthermore, any device allowing a thief hatch to open to atmosphere would be creating emissions and would be the opposite of a thief hatch. Redline required as a storage tank is a confined space, if there ever needs to be "human ingress" the tank will need to be drained and the manway removed to provide access. At that point there is no need to worry about whether a thief hatch is opened or closed as the tank will no longer contain any liquids.

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

(1) ~~monitor~~ on a monthly basis, calculate or estimate the total monthly liquid throughput (in barrels) and record the upstream separator pressure (in psig) if the storage vessel is directly downstream of a separator. 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 25 of 20.2.50.112 NMAC;~~

(2) 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

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

Comment on 20.2.50.123(C)(1): Redline in (C)(1) necessary because operators do not monitor throughput to each and every tank, but estimate or calculate the monthly liquid throughput through each tank based on total throughput through the manifolded vessel.

Comment on 20.2.50.123(C)(2)-(3): Redline required as 2 and 3 are duplicative of 20.2.50.116.

D. Recordkeeping requirements:

(1) The owner or operator shall, on a monthly basis, maintain a record in accordance with 20.2.50.112 NMAC for a storage vessel. The record shall include:

(a) the vessel location and identification number;

(b) calculated or estimated monthly liquid throughput~~; and the most recent date of measurement;~~

(c) the ~~average monthly~~ upstream separator pressure, where applicable;

(d) the data and methodology used to calculate the actual emissions of ~~PTE~~ of VOC (~~the Calculation methodology shall be department approved);~~

(e) the controlled and uncontrolled VOC emissions (tpy); and

(f) the type, make, model, and identification number of any control device.

(2) A record of liquid throughput in shall be ~~verified~~ estimated by liquid level measurements, a dated delivery receipt from the purchaser of the hydrocarbon liquid, the metered volume of hydrocarbon liquid sent downstream, or other proof of transfer.

(3) A record of the inspection required in Subsection C of 20.2.50.123 NMAC shall include:

(a) the time and date of the inspection;

(b) the ~~personnel~~ person(s) conducting the inspection;

~~**(c)** a notation that the required leak check was completed;~~

(~~d~~c) a description of any problem observed during the inspection; and

(~~e~~d) a description and date of any corrective action taken.

(4) An owner or operator complying with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

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

Comment on 20.2.50.123(D)(1)(b): Redline required as this data point has limited to no value.

Comment on 20.2.50.123(D)(1)(c): Redline required as operator is only required to monitor upstream separator pressure monthly, so shouldn't be required to keep record of "average monthly" separator pressure.

Comment on 20.2.50.123(D)(1)(d): Redline required as PTE is a one-time calculation so there is no reason to track the calculation method monthly. The intent is to probably record the method for calculating actual monthly emissions required in (e). Redline required as it is the operators' responsibility to develop methodology using best industry/engineering practices and present the findings to the Department.

Comment on 20.2.50.123(D)(2): Redline required as this addition is necessary as there would be no way to determine tank throughput for a tank that doesn't have a load hauled within a month and because, within tank batteries, operations do not measure throughput to each tank, but would estimate or calculate the monthly liquid throughput through each tank based on *total throughput*

Comment on 20.2.50.123(D)(3)(c): Redline required as the inspection itself is the required leak check, making this notation redundant.

E. Reporting requirements:

(1) An owner or operator complying with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.15 NMAC.

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

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

20.2.50.124 WELL WORKOVERS

A. Applicability: Workovers performed at oil and natural gas wells are subject to the requirements of 20.2.50.124 NMAC as of the effective date of this Part.

B. Emission standards: The owner or operator of an oil or natural gas well shall use the following best management practices during a workover to minimize emissions, consistent with the well site condition and good ~~engineering~~ operational practices:

(1) reduce wellhead pressure before blowdown to minimize the volume of natural gas vented;

(2) monitor manual venting at the well until the venting is complete; and

(3) route natural gas to the sales line, if possible.

C. Monitoring, testing or inspection requirements:

(1) The owner or operator shall monitor the following parameters during a workover:

(a) wellhead pressure;

(b) flow rate of the vented natural gas (to the extent feasible); and

(c) duration of venting to the atmosphere.

(2) The owner or operator shall calculate the estimated volume and mass of VOC vented during a workover.

(3) 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 record for a workover:

(a) identification number and location of the well;

(b) date the workover was performed;

(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 estimated VOC emissions vented during the workover based on the duration, volume, and ~~mass~~ gas composition 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.

(3) Notification exception for ~~emergency~~ routine downhole maintenance operations to restore production lost due to upsets or equipment malfunction, allowing the owner or operator to notify all residents located within one-quarter mile of the well of the planned workover at least 24 hours before the workover event.

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

Comment on 20.2.50.124(C)(1)(2), (D)(1)(g): Redline required because well liquids unloading vented gas is calculated, not measured, and calculations may involve some degree of estimation.

Comment on 20.2.50.124(E)(2)-(3): Redline required as certified mail delivery times vary, and this requirement does not allow for more advanced technology or concepts.

Comment on 20.2.50.124(E)(3): Redline required as routine downhole maintenance workovers are downhole intervention *activities that are required to restore production from a well by performing downhole maintenance or repair which would include but is not limited to a pump change, tubing swap or clean out. This would not include pay adds or recompletion type workovers. This exception is necessary to allow for the flexibility to perform routine downhole maintenance and not have an unnecessary delay with the notification process. The efficient use of a workover rig in the field requires this flexibility to ensure wells in an area can be serviced while a rig is in close proximity.*

~~**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 NOx 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 NOx 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 NOx emissions from each facility and the company-wide VOC and NOx 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]~~

Comment on 20.2.50.125. NMOGA cannot identify any oil and gas owners or operators in the state that qualify under NMED's definition of a small business facility. While it is appropriate to take steps to reduce the economic impact of the rule on small operators, the employee and financial thresholds would need to be increased to achieve this objective.

20.2.50.126 PRODUCED WATER MANAGEMENT UNITS

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~~ operational practices to minimize emissions of VOC from produced water management units.

(2) The owner or operator shall calculate uncontrolled PTE for each produced water management unit. If the PTE exceeds the threshold specified in 20.2.73.200 the owner or operator shall submit a Notice of Intent to NMED for approval. If the PTE exceeds thresholds established in 20.2.72.200 ~~control~~ file an appropriate permit application ~~VOC emissions from~~for each produced water management unit. Existing produced water management units with uncontrolled PTE that exceeds the thresholds in 20.2.73.200 or 20.2.72.200 may continue to operate until the application is approved or denied by the Department. ~~to less than two tons per year.~~

C. Monitoring, inspection or testing requirements: The owner or operator shall:

(1) calculate the monthly rolling 12-month total of VOC emissions in tons from each unit with first month of emission calculation beginning within 180 days after the effective date of this Part;

(2) monthly, monitor the best management and ~~engineering~~ operational 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~~operational practices used to minimize release of VOC at the produced water management unit; and

(c) a record of the monthly rolling 12-month total VOC emissions from each produced water management 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]

Comment on 20.2.50.126(B)(2): As NMOGA communicated on the pre-proposal, there are operational and technical design infeasibilities with installing and maintaining barrier controls to reduce emissions on large ponds. In addition, there is a lack of data to show effective emission reductions that could be placed on the Produced Water Ponds, in lieu of reducing produced water recycling, to achieve two tons per year. These Produced Water Management Units are integral to recovering and treating produced water for reuse, and this proposed emission limit would reduce or eliminate the goal of recycling produced water for drilling operations, inconsistent with the Legislature's intent in the Produced Water Act. To move towards improving NMED's emission inventory and operational data set on these Produced Water Management Units, NMOGA proposes to update a current General Construction Permit (GCP) to include Produced Water Management Units. Until the GCPs have been updated to include Produced Water Management units, NMOGA suggests utilizing the current NOI and permitting processes to continue management of these facilities.

Comment on 20.2.50.126(C)(1): Redline required as monthly data will not be available immediately at the effective date, therefore time is needed to accumulate data.

20.2.50.127 PROHIBITED ACTIVITY AND CREDIBLE INFORMATION PRESUMPTION

A. Failure to comply with the emissions standards, monitoring, testing, inspection, 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~~information~~ obtained by the department demonstrates an alleged violation ~~indicates that a source is not in compliance~~ ~~with~~of the provisions of this Part, the source shall have an opportunity to provide ~~be presumed to be in violation of this Part unless and until the owner or operator provides~~ credible evidence or information demonstrating otherwise.

C. If ~~credible~~ information is provided to the department by a member of the public ~~indicates~~ indicating that a source may~~is~~ not be in compliance with the provisions of this Part, the Department may initiate enforcement action under Section 74-2-12 NMSA 1978 only if the Department determines the information is of sufficient value and credibility and demonstrates that a violation occurred. In evaluating whether the information is of sufficient value and credibility of information provided by a member of the public and determining the use of such information as evidence in an enforcement action, the Department shall consider the following criteria:

(1) the member of the public providing the information must be willing to submit a sworn affidavit attesting to the facts that constitute the alleged violation and authenticating any writings, recordings, or photographs provided by the individual;

(2) the individual providing the information must be willing to make themselves available to the Department and alleged violator regarding the alleged violation, including as necessary to testify in any enforcement proceedings regarding the alleged violations;

(3) if the Department relies on any physical or sampling data submitted by an individual to prove one or more elements of an enforcement case, such data must have been collected or gathered in accordance with relevant agency protocols and the individual must be willing to submit a sworn affidavit demonstrating that it followed relevant agency protocols when collecting the data,~~;~~ and the Department must ensure that the physical or sampling data was collected through an accepted and verifiable methodology.

(4) the Department will not use in an enforcement action information gathered by an individual illegally,

including pursuant to trespass.
~~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]

Comment on 20.2.50.127. NMOGA opposes subsections 20.2.50.127(B) and (C) of the proposed rule because they would establish legally invalid presumptions and fail to define "credible information" or "credible evidence" for purposes of either establishing or rebutting such a presumption. The proposed rule would establish a presumption of noncompliance based on "credible information" received from a third-party and allow enforcement actions to be brought only based upon indication of noncompliance. However, the rule fails to define "credible information" and "credible evidence," and places potentially insurmountable burdens on operators to provide evidence to rebut an allegation by either the Department or the public.

The Constitution of the United States and New Mexico endow all accused with the presumption of innocence, which "extends to every element of the crime." Morissette v. United States, 342 U.S. 246, 275 (1952). Those subjected to NMED's proposed presumption would be vulnerable to criminal prosecution under N.M.S.A. 1978, § 74-2-14, and their right to be presumed innocent would be infringed under NMED's framework. NMED's proposal also offends the innocence presumption in cases where crimes are not at issue due to the risk of erroneous deprivation from unwarranted civil penalties. Harjo v. City of Albuquerque, 307 F. Supp. 3d 1163, 1211 (D.N.M.) (citing Nelson v. Colorado, 137 S. Ct. 1249, 1256 (2017)).

Information used for enforcement must be scientifically reliable, legally defensible, and subject to defined methods of detection and reporting. The proposed rule fails to meet these minimum criteria and would establish a presumption of noncompliance based on undefined "credible information" received from a third party or just indications of non-compliance from the agency. The proposed rule similarly fails to define what will be considered "credible evidence" sufficient to rebut this presumption. This lack of specificity places potentially insurmountable burdens on operators to provide evidence to rebut an allegation by either the Department or the public. Such a rule, if adopted, would violate operators' due process rights. More specifically:

1. "Credible Information" and "Credible Evidence" are not defined terms. "Credible information" would apply to information obtained by NMED and information provided to NMED by the public. "Credible evidence or information" would apply to rebuttal of "credible information." It is unclear whether these meant to be the same, regardless of who obtains the information, or different?
2. The breadth of compliance information already submitted and readily available to the Department weighs against a presumption of noncompliance based on third-party information. This is particularly so given that the third-party "credible information" is not subject to any requirements related to quality control—e.g., data collection method, chain of custody documentation, etc. Technology to detect emissions is evolving (satellites, flyovers, drones, etc.) and the oil and gas industry has partnered with vendors, NGOs and academic institutions to assess the usefulness of new technology. However, many of these alternative methods of detection are not commonly available or not yet capable of providing data that can be used to determine compliance. New technologies have shown great promise in detecting emissions at a lower cost, but there is generally a trade off in terms of detection limit and ability to pinpoint the location of a leak. Thus, the agency must demonstrate that the data is of sufficient value and credibility and that a violation has occurred before it may bring an enforcement action.
3. Regardless of the method of detection, it is critical to understand how to use the technology and to ensure that it is properly functioning and calibrated so that the resulting data is reliable and, if necessary, replicable. Users must document how the method was used, confirm the tool was working correctly, and demonstrate a chain of custody. The Department must demonstrate that each of the above indicates that a violation has occurred before it may bring an enforcement action.
5. If an operator does not obtain the "credible information" until days, weeks, months or years after it was created, it will be difficult, if not impossible, to verify (or refute) the credibility of the information through subsequent investigation. Thus, the Department must not assume a violation based upon this data, but must evaluate the data to determine if it in fact is sufficient value and credibility to demonstrate a violation.
6. Without establishing minimum criteria and a requirement for the Department to determine a violation in fact occurred, the burden of proof for credibility is a low and easy threshold to surpass, allowing almost any type of accusation of non-compliance by NMED or the public to be alleged.
7. Encouraging submission of "credible information" by the public, without any safeguards or limitations, will undoubtedly create situations that put members of the public in immediate danger, as well as operators' employees and contractors. During state and federal regulatory or enforcement agency inspections, an operator representative must be allowed to accompany a trained, experienced inspector. Encouraging citizen inspections, without appropriate safeguards, may lead to situations where untrained, inexperienced members of the public are trespassing by attempting to enter on or come near facilities to collect information, putting not only themselves, but operators and other community members at risk.
8. The proposed rule is inconsistent with the Department's current regulation for use of credible evidence in 20.2.72.218

NMAC. That existing rule provides that credible evidence may be used for the purpose of establishing whether there has been a violation; however, it only establishes a presumption of noncompliance for specific methods, including monitoring required by an operating permit and compliance methods in the State Implementation Plan as well as data from federally enforceable monitoring or test methods under 40 CFR Parts 51, 60, 61 and 75 and other test or monitoring methods that produce comparable data to the above. This is vastly different from the proposed rule where the Department has not included any boundaries (technical or procedural) around what may be credible information. If the Department wants to encourage the use of credible evidence of compliance issues, it must develop criteria for how the evidence is collected, by both the agency and the public, and how it will be used by the agency. For example, the Texas Commission on Environmental Quality's (TCEQ) complaints protocol, https://www.tceq.texas.gov/compliance/complaints/protocols, establishes criteria and procedures for the collection of information that may be used by TCEQ in enforcement. TCEQ requires the use of agency protocols, procedures or guidelines when collecting and submitting information or evidence, proper chain of custody and, perhaps most importantly, does not presume a violation upon receipt of information or evidence. Instead, the agency will evaluate the information and require the person submitting the information to authenticate the information and participate in an enforcement hearing if one is necessary and thus subject to cross-examination. NMOGA recommends that the credible information sections 20.2.50.127 B and C be removed from the rule or significantly revised, consistent with the above revisions proposed by NMOGA, to address these legally invalid presumptions.

HISTORY OF 20.2.50 NMAC: [**RESERVED**]