EXHIBIT 1

Montana Board of Oil & Gas Conservation
Public Hearing – Wednesday-June 11, 2025

Board Members

Steve Durrett – Chair
Roy Brown
Barbara Skelton
Mac McDermott
John Tietz
Corey Welter
Jeff Wivholm

Patrick M. Montalban, CEO
Montalban Oil & Gas Operations, Inc
Chairman & Executive Director – National Stripper Well Association (NSWA)
Executive Director & Secretary Treasurer – Domestic Energy Producers Alliance (DEPA)

NSWA National Stripper Well Association

NSWA| 2313 N BROADWAY | ADA, OK 74820 | 405.228.4112 | WWW.NSWA.US

Thursday, May 22, 2025

Doug Burgum, Secretary
United States Department of the Interior
1849 C Street NW
Washington, DC 20240

Dear Mr. Secretary Burgum:

Thank you for this opportunity to provide input on behalf of the small independent oil and gas operators in North Dakota, Montana and across the United States. The small independent operator has gone through 16 years of rigorous regulatory control from the Bureau of Land Management and the Department of Interior. This is the first opportunity we have had to provide our thoughts regarding what is necessary to reduce the regulatory burden on stripper well operators in this country.

The following are what we feel are the most critical issues and our suggestions for change:

1) Bonding on Federal lands for single well bonds has gone from $10,000 per well to $150,000 per well. This should be reduced to $25,000 for a single well bond.

   Bonding on Federal lands for multiple wells bonds went from $25,000 to $500,000. This should be reduced to $50,000.

2) On-shore plugging and abandonment practices and procedures should follow State regulations and should not exceed the State regulatory requirements.

3) With respect to 43CFR 3163.1.b – "Remedies for Acts of Non-Compliace (INC) there is the use of a "without exception" phrase regarding when to implement a $1,000 immediate assessment when conducting field inspections. We feel there are exceptions that may need to be considered before issuing an immediate assessment to an operator, especially a small independent operator. There are three oil and gas regulations that reference this "without "exception" phrase:

   - 43CFR 3173.29 – Site Security & Production Handling
   - 43CFR 3174.15 – Measurement of Oil
   - 43CFR 3175.15 – Measurement of Gas

   The "without exception" phrase needs to be eliminated from the regulations and be left up to the discretion of the field inspector.

4) The regulations currently require an operator to calibrate meters, take gas samples for analysis, and undergo field inspections annually. We would like to have the option of requesting a variance to conduct this testing and inspection

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every two years. For stripper well production the BTU content, determined by the gas, does not change over a brief period of time.

5) The new "Right of Way" (ROW) bonding requirements are absolutely astronomical and will keep the small independents from being able to operate on Federal Lands.

6) The reporting of oil and gas production and payment of royalty through the ONRR system is onerous and confusing. For a small independent operator, often having limited office personnel, it becomes an overwhelming task to stay on top of the constant compliance reviews and reporting requirements.

7) We must remove the regulation that does not allow for a run-over line on a stock tank. If an accident occurs, we must be able to run into a second tank.

Again, we thank you for the opportunity to express our concerns and suggestions for regulatory change.

Thank you for your time and consideration.

Sincerely,

Patrick M. Montalban
Chairman, National Stripper Well Association
Chairman & CEO, Montalban Oil & Gas Operations, Inc

Carla Barringer

From:	Patrick Montalban
Sent:	Thursday, June 5, 2025 11:11 AM
To:	Carla Barringer; Joseph Montalban
Subject:	Fwd: (NSWA LETTER) - Doug Burgum - Bonding

Here is the CFR letter.

Patrick
Sent from my iPhone

Begin forwarded message:

> **From:** Sam Bradley <sbradley.impetro@gmail.com>
> **Date:** May 27, 2025 at 10:07:50 AM MDT
> **To:** Patrick Montalban <Patrickm@mogo-inc.com>
> **Cc:** Ann Cook <acook@nswa.us>, Matt Nelson <matt@chacoenergy.com>
> **Subject: Re: (NSWA LETTER) - Doug Burgum - Bonding**
>
> Ron - Please see the follow-up below regarding BLM Bonding and listing the CFR's you requested. ROW bonding is very complicated and we tried to make it short but it is tough.
>
> 1. Bonding on Federal lands increased significantly with the revision of 43 CFR 3104.1 "Bond Amounts." This rule replaced 43 CFR 3104.2 "Lease Bond" and 43 CFR 3104.3 "Statewide and National Bonds." Lease bonds were increased from $10,000 per lease to $150,000 per lease, statewide bonds were increased from $25,000 per state to $500,000 per state and nationwide bonds were eliminated with the implementation of 43 CFR 3104.1. This increase of 15 and 20 times respectively places an undue economic burden on small operators. A reduction in bonding requirements to $25,000 per lease and $50,000 per state is respectfully requested.
>
> 2. 43 CFR 2805.20 outlines bonding for rights-of-way granted on Federal lands. This rule stipulates the BLM "may" require a reclamation bond or other acceptable bond instrument when a right-of-way is granted. Circumstances that trigger bonding requirements (and exemptions) are not discussed in 43 CFR 2805.20, rather they are set in Instruction Memorandum ("IM") 2019-013 "National Policy for Rights-of-Way Bonding." The bonding process is arduous, and bond amounts often seem arbitrary due to lack of transparency from the BLM. An operator may go through the effort of bidding out reclamation work when preparing a Reclamation Cost Estimate ("RCE") only to be told the dollar amount in the RCE does not meet minimum requirements. The BLM does not disclose their process for determining said minimum requirements or what that minimum dollar amount per acre is. In addition to this, once a dollar amount has been agreed to the BLM requires an additional approximate 60%-80% increase in the bond amount to cover Federal administrative costs. It is common for bonds on individual rights-of-way to reach into the

tens to hundreds of thousands of dollars. Considering that most small operators using Federal lands to access oil and gas leases have many grants with the BLM, these bonding requirements place an undue economic burden on small operators.

Many rights-of-way used to access oil and gas locations are also used by private landowners and/or the public. It is common that these rights-of-way will remain in use after oil and gas operations cease for the beneficial use of the private landowner and/or the public. The BLM does not take beneficial use into account and operators are still expected to post a bond for these rights-of-way.

Most rights-of-way currently in use by small operators to access oil and gas leases were granted decades ago. Most of these grants did not stipulate a bond was required as a condition of the grant. These grants expire after a period of time specific to each grant, after which the operator is required to renew a grant. Renewal of a grant now triggers bonding requirements. Bonding is also now required to transfer or amend a grant.

It is respectfully requested that the following changes be made to 43 CFR 2805.20:

- 43 CFR 2805.20(e) – A bond shall not be required where a grantee can demonstrate beneficial use of a right-of-way for a private landowner and/or the public.
- 43 CFR 2805.20(f) – In the event there is a dispute regarding RCE amount, the BLM shall disclose and make transparent all costs and assumptions used to deny said RCE.
- 43 CFR 2805.20(g) – Bonding shall not be required to renew, assign or amend a grant that did not originally have bonding as a condition of the grant.
- 43 CFR 2805.20(h) – All existing federal wells will have rights-of way grandfathered / covered under the well bond. All new rights-of-way can be covered with a maximum $50,000 multiple state blanket bond.
- 43 CFR 2805.20(i) – Administrative costs associated with RCEs shall be capped at 10%.
- Amendment to 43 CFR 2805.20(a)(2) - ***Bond acceptance.*** The BLM authorized officer must review and approve all bonds, including any State bonds, prior to acceptance. ~~and at the time of any right-of-way assignment, amendment, or renewal.~~

Thanks,

Sam Bradley, Impetro NonOp LLC, 970-593-8626

Matt Nelson, Chaco Energy Company, 303-981-3840

Patrick Montalban, MOGO Inc., 406-450-3152

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DEPA
DOMESTIC ENERGY PRODUCERS ALLIANCE

NSWA
National Stripper Well Association

FOR IMMEDIATE RELEASE
May 16, 2025

Contact: Patrick Montalban
Phone: 405-228-4112
EMAIL: pmontalban@nswa.us

SMALL ENERGY PRODUCERS APPLAUD EPA'S PRO-GROWTH VISION, URGE REPEAL OF BURDENSOME METHANE RULES

TULSA, OK — The Domestic Energy Producers' Alliance (DEPA), joined by the National Stripper Well Association (NSWA), today released a letter to Environmental Protection Agency Administrator Lee Zeldin, applauding the agency's efforts to restore regulatory balance and urging the repeal of costly and duplicative methane regulations that disproportionately harm America's smallest energy producers.

In the letter, the organizations commend Administrator Zeldin for his leadership in pursuing the repeal of the 2009 Endangerment Finding and in advancing a regulatory framework that supports both environmental stewardship and energy independence. They also urge the EPA to formally rescind several methane-related rules and reporting mandates that impose severe compliance burdens on small, independent oil and natural gas producers.

"Administrator Zeldin is rightly shifting the EPA away from politically motivated overregulation and toward a science- and results-based framework that supports American innovation and energy security," said **Jerry Simmons**, CEO/President of the Domestic Energy Producers' Alliance. "The data shows our industry has made tremendous strides in reducing methane emissions—not because of sweeping federal mandates, but because our producers are committed to efficiency, innovation, and environmental responsibility. These outdated rules must go."

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Methane emissions from natural gas systems have declined significantly—even as U.S. oil and gas production has hit record highs. EPA's own data shows a 21% reduction in methane emissions from natural gas systems between 1990 and 2022. In regions like the Arkoma, Appalachian, and Anadarko Basins, industry-led efforts have driven methane reductions ranging from 45% to 87% in just the last four years.

However, the cost and complexity of complying with rules such as Subpart W of the Greenhouse Gas Reporting Program and New Source Performance Standards (Subparts OOOO, OOOOa, OOOOb, and OOOOc) place a crushing burden on small producers—those least able to absorb regulatory overhead.

"As a small, family-owned oil and gas company in rural Montana, we find these methane rules and reporting requirements simply unmanageable," said **Patrick Montalban**, President of the National Stripper Well Association and owner of Montalban Oil and Gas Operations. "NSWA members are responsible operators who care deeply about protecting the environment and provide a vital source of income for millions of royalty owners—many of them retirees on fixed incomes who depend on their monthly checks to make ends meet. But small producers cannot afford to hire teams of compliance officers or invest in one-size-fits-all technologies built for billion-dollar corporations. These rules threaten the very survival of the small businesses that power American energy, support rural communities, and help secure our nation's energy future."

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The organizations argue that voluntary efforts and industry innovation—not federal mandates—are the true drivers of emissions progress. They emphasize that repealing the regulations in question will not reverse environmental gains, but rather empower operators to continue delivering clean, affordable energy without unnecessary bureaucratic hurdles.

About DEPA:

DEPA is a nationwide collaboration of 39 coalition associations – from California to West Virginia, Texas to Montana – representing individuals and companies engaged in domestic onshore oil and natural gas exploration and production. DEPA is a non-partisan association seeking common ground, and in common sense solutions to the challenges facing American oil and natural gas production.

About NSWA:

The National Stripper Well Association (NSWA) is the sole group in the U.S. advocating on behalf of producers, owners and operators of marginally producing wells. For more information, visit www.nswa.us.

###

We Are the People of American Oil and Natural Gas
DEPA
DOMESTIC ENERGY PRODUCERS ALLIANCE

NSWA
National Stripper Well Association

The Honorable Lee Zeldin
Administrator
Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, DC 20004

May 14, 2025

Dear Administrator, Zeldin,

We commend your bold leadership at the EPA, particularly your efforts to repeal the 2009 Endangerment Finding and roll back burdensome regulations. These actions align with prioritizing economic prosperity, energy security, and common-sense governance. By reconsidering the Endangerment Finding, you are taking a critical step to alleviate trillions in regulatory costs that have strained American families and industries, while still committing to clean air, land, and water. Your focus on unleashing American energy and revitalizing the auto industry reflects the needs of hardworking citizens. We fully support your vision to power the great American comeback through deregulation and cooperation with states.

Over the past decade, our industry has achieved remarkable environmental progress, driven by technological innovation, operational efficiency, and a deep-rooted culture of responsible energy development. The data supports what we have seen on the ground: methane emissions from natural gas systems have declined substantially—even as production has reached record highs. According to the EPA's own Greenhouse Gas Inventory, methane emissions from natural gas systems fell by approximately 21% between 1990 and 2022, despite production more than doubling during that same period.

Independent research and basin-specific data further confirm this trend. From 2019 to 2023, methane emissions dropped by 45% in the Anadarko Basin, 52% in the Appalachian Basin, and a full 87% in the Arkoma Basin. Even in the prolific Permian Basin, emissions declined by 32% while oil and gas production soared by more than 50%. These results were achieved not because of federal mandates, but because our industry invested in innovative technologies, implemented best practices, and recognized the business and environmental imperative of reducing waste.

Moreover, the expanded use of natural gas—enabled by responsible production—has played a significant role in reducing national greenhouse gas emissions. The transition from coal to natural gas in the electric power sector has driven the largest share of U.S. emissions reductions over the last two decades. In fact, natural gas accounted for nearly all of the electricity generation gains that offset a 121.9 terawatt-hour drop in coal-fired generation in 2023 alone.

Given this track record, we respectfully request that the EPA formally repeal the following methane-related rules and reporting mandates:

- **Subpart W** of the Greenhouse Gas Reporting Program
- **New Source Performance Standards (NSPS) Subparts OOOO, OOOOa, OOOOb, and OOOOc**

To reiterate our arguments to repeal of the methane regulations:

1. **Demonstrated Emissions Reductions Without Regulatory Mandates**: Significant decreases in methane emissions have occurred alongside increased natural gas production, suggesting that industry-led initiatives and technological advancements are effective.

2. **Economic Efficiency**: Eliminating redundant regulations can reduce compliance costs for the industry, potentially leading to lower energy prices for consumers.

3. **Energy Security and Reliability**: Natural gas provides a stable and reliable energy source, essential for meeting current and future energy demands. (Historic 17% decline in US greenhouse gas emissions would not have been possible without natural gas -)

4. **Support for Renewable Integration**: Natural gas serves as a flexible backup for intermittent renewable energy sources, facilitating a smoother transition to a low-carbon energy grid.

These regulations are redundant, impose excessive compliance costs, and do not reflect the reality of our industry's environmental performance. We believe in environmental accountability—but also in common-sense regulation. Rolling back these rules will not reverse our progress of emissions. Rather, it will affirm that voluntary action, innovation, and trust in operators can achieve better outcomes than outdated, one-size-fits-all mandates.

Administrator Zeldin, we thank you for your leadership and your commitment to restoring regulatory balance. We look forward to collaborating with you to ensure America's energy future is clean, secure, and economically strong.

Sincerely,

Jerry Simmons, President/CEO
The Domestic Energy Producers Alliance (DEPA)

Patrick Montalban, President
The National Stripper Well Association (NSWA)

From: Jarod Bailey, EPA

To: Chris Kearney, NSWA

Via email 05/27/2025

Hi Chris,

Worked with our technical staff and have come up with the below 8 questions for you and your team:

1. What is a stripper well and how do these differ, in your opinion, from marginal and low production wells or are they all the same thing?
    - We dislike the "Marginal and low production" term because it is ambiguous and messy. We prefer to look at wells as either "Stripper Wells" or not.
    - "Stripper Well" is defined in Federal and State statutes as a well that produces less than an annual average of 15 barrels of oil per day (BOPD) or 90,000 cubic feet of gas per day (90 MCFD) or 15 barrels of oil equivalent per day (BOED)
        - *Internal Revenue Code section 45I and others*
        - *Colorado tax code Section 39-29-105(1)(b) and others*
    - "Marginal Well" or "Low producing well" can produce at a greater or smaller quantity than "Stripper Well"
        - EPA Natural Gas STAR Program *"Marginal conventional wells are... wells... that produced less than or equal to 15 barrels of oil equivalent per day..."*
        - IRS Form 8904 (revised 10/2024) – *"Qualified marginal well means ... the production from which during the tax year... Has average daily production of not more than 25 barrel-of-oil equivalents ..."*
        - Colorado ECMC *definition "...an oil or gas Well that produces a daily average of less than 2 barrels of oil equivalent ("BOE") or 10 thousand cubic feet of natural gas equivalent ("MCFE") of gas over the previous 12 months.*

2. Are you aware of any studies that attempt to estimate emissions profiles, including malfunctions, specifically at marginal wells?

   - IMPORTANT CONTEXT No matter which of the below studies you believe the grand total emissions from US Stripper Wells is less than 1% of total annual US emissions (we believe it is 0.2% or two tenths of a percent). This is such a small contribution that the success case is impossible to measure. Said different... the cost vs benefit analysis does not work because the benefit is negligible, so any cost is not justified. The work, lost jobs, lost tax revenue and lost royalty for a 25% or 50% stripper well emission reduction is simply not cost beneficial.
   - Yes, and the results and conclusions vary widely... we have extensive experience and expertise across our membership, and we have conducted our own review of the studies and have concluded the following:
     - Per Department of Energy (DOE) study from 2022 (Quantification of Methane Emissions from Marginal (Small Producing) Oil & Gas Wells) and EPA published data total annual US stripper well emissions are 22 million metric tons of CO2 Equivalent (CO2e) or 0.2% of Total U.S. emissions (12,686 million metric tons).
       - Less than 50% of well sites had detectable methane emissions
       - A copy of this report is included at the bottom of this attachment.
     - Per a random sample of 20 member companies 100% are less than 25,000 metric tons of CO2e per year
       - Well count ranged from 29 wells to 650 wells
       - Largest company average well was 10 BOEPD/well
   - Other studies exist from the government and universities.
     - Colorado State University - Energy Institute focusing on "unplugged abandoned" estimated annual total U.S. methane emissions of 1.6 tons of CO2e from these wells. – THIS WAS MEASURED AND METERED by CSU
       - *"The term abandoned describes a range of well types including: 1. wells with no recent production, and not plugged*

(inactive, temporarily abandoned, shut-in, dormant, idle); 2. wells with no recent production and no responsible operator..."

- EPA Natural Gas STAR Program
    - Omara et al study at 100 million tons CO2e per year and Bowers et al study at 25 million tons CO2e per year
        - Omara was based on Environmental Defense Fund (EDF) publications
        - Bowers had operators involved and access to wellsites
        - If you dig into these EDF publications the assumptions are highly flawed from real world. **THE MAORITY OF STRIPPER WELLS DO NOT HAVE PNEUMATIC CONTROLLERS**
        - EDF Estimates pneumatic controllers cycle continuously 24/7/365 when in reality stripper well controllers cycle a few times per week
        - Assume storage tank emission factors are several orders of magnitude greater than reality

3. We are interested in understanding operating cost information for gas and oil wells, respectively. It would be helpful for us to see consistent representative costs for both gas and oil wells for both fixed costs ($/well/month) and variable costs ($/mcf) or ($/bbl), and for different states/regions.

    - This data is highly variable across different companies and well portfolios. The important thing is that the margins are incredibly slim.
    - Below is an example of one member companies 2024 financials.
        - Oil & Gas Sales Volume = 41,706 BOE
        - Revenue = $3,212,413
        - 2024 Non-Fed Tax = $256,013
        - Operating Expenses (at the well) = $2,633,995 ($63/BOE)
        - Net Cash Flow = $322,405 or **<u>$4,187 per well</u>**
        - This is before back-office, salaries, or debt servicing.

4. There are more than 150,000 natural gas wells producing less than one BOEd. Back of the envelope calculations suggest these sites are unprofitable. What are the factors keeping these wells from being plugged?

    - This is not and should not be the focus of EPA and air regulations however is a fair question and the answer is... not much. There are a variety of tools that operators use to survive during low price runs. Wells can be shut in for years and decades at a time and brought back to production when prices are high... this is the entire business plan of stripper well operators. This works as long as the regulatory environment doesn't drastically change and kill the business model (as we have seen in the last 5-10 years).
        - Many unprofitable wells are produced to hold leases that cash flow from other operators drilling wells or future planned drilling.
    - Think about the tremendous burden on the public if 150,000 wells suddenly became orphan wells. The best place for these assets to remain is in the private domain cared for by stripper well operators.
    - One operator turned on an oil well when prices were high after COVID that had been shut in since 1984 and the well peaked at 80 BOPD... this is the business model.

5. How important is the sale of natural gas liquids to making marginal gas wells profitable?

    - As discussed in the introduction, the US stripper well portfolio is highly complex, variable and heterogeneous. There are many stripper wells in legacy producing basins that make primarily wet gas and are tied to gathering systems with processing (Hugoton in Kansas, Wattenberg in Colorado, multiple fields in every producing state). Natural Gas Liquids (NGL's) are essential to keeping those wells profitable. We estimate this revenue stream is essential to tens of thousands of stripper wells.
        - The vast majority of the gathering & processing operations are done by third party pipeline companies... not by stripper operators.

6. We understand some owners/operators of marginal wells would prefer EPA have an AVO (LDAR) standard for process controllers. We understand from a literature review that AVO does not sufficiently identify malfunctioning process controllers all the time. Have your companies found issues using AVO for process controllers? Have your companies found AVO to be effective for process controllers? Given that

it appears AVO is much less effective for emission reductions for process controllers, do folks do anything to help AVO be more effective or what else do operators do to identify malfunctions (e.g. OGI)?

- Wonderful questions. We strongly support AVO-LDAR as the inspection standard.
- No inspection identifies malfunction process controllers all the time... training and experience is required. We have seen many examples of OGI surveys being incorrect due to training and calibration (i.e. heat and steam mistaken or emissions)
    - OGI is done by third parties who are not familiar with the wells and are low frequency inspections.
- AVO has been industry standard decades and generations. The workforce is highly trained in this and it is the first line of defense for every onsite worker (think logically, look, listen, smell). This is absolutely an effective practice for identifying malfunctioning process controllers.
    - Workers perform these inspections daily or weekly and are very familiar with the wells. In practice AVO by stripper well operators is the most effective LDAR.
- We strongly oppose the idea that OGI is "better" than AVO. The workforce is much less trained in this technology and calibration is always an issue. The cost benefit of OGI is not present. Current regulations require stripper wells to incur at least $400/year in OGI costs and compressors at least $800/year in OGI costs. If you follow the logic of cost benefit, there is no way this cost is beneficial in a measurable way.

7. If marginal wells had even more time to comply with a zero emission standard for process controllers would that help marginal wells comply with the zero emission standard?
    - No. There is no success case for all stripper wells becoming zero emission. They would become orphans and the US would lose a meaningful 7-10% of domestic production and be burdened with hundreds of thousands of orphan wells.

- Current estimated costs associated with converting an average stripper well to be zero emissions is at least $15,000 and goes significantly up from that number depending on the well.

8. How technically challenging and costly is it to switch an intermittent controller to a low bleed controller?

    - Technically... simple. Practically, expensive and not cost effective. Current estimated costs associated with converting an average stripper well to new low bleed controllers is $10,000.

    - Stripper well operators are smart and creative. There is more than one way to skin a cat. For example, in Colorado (due to Reg 7) stripper operators had to find a way to deal with this. What many did is run pipe from the bleed valve to the burner so the fumes were burned instead of vented. In the end air regulations and other regulations caused many (thousands) of wells to be shut-in and become orphan wells. This is a real world, verifiable example of the consequences of poor regulation.

EXHIBIT 2

FINAL PROJECT REPORT

US DOE NETL Award Number DE-FE0031702

Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells

Issued: 28 April 2022

Prepared for: U.S. Department of Energy
National Energy Technology Laboratory

GSI ENVIRONMENTAL

GSI Environmental Inc.

9600 Great Hills Trail, Suite 350E ■ Austin, TX 78759 ■ P: 512.346.4474 ■ www.gsienv.com

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APPENDICES

Abbreviations and Acronyms

BHFS .... Bacharach hi-flow sampler
BOE .... Barrels of oil-equivalent
CSU .... Colorado State University
DOE .... Department of Energy
EIA .... Energy Information Administration
EPA .... Environmental Protection Agency
GHGRP .... Greenhouse Gas Reporting Program
GSI .... GSI Environmental Inc.
IOGCC .... Interstate Oil & Gas Compact Commission
LDAR .... Leak detection and repair
METEC .... Methane Emissions Technology Evaluation Center
MBOE .... Thousand barrels of oil-equivalent
MCFD .... Thousand cubic feet of gas per day
NEPA .... National Environmental Policy Act
NETL .... National Energy Technology Laboratory
NSPS .... New Source Performance Standards
OGI .... Optical gas imaging
OTM .... Other Test Method
QA/QC .... Quality assurance/quality control
scfh .... Standard cubic feet per hour
TASC .... Technical Advisory Steering Committee
TPY .... Tons per year

1.0 EXECUTIVE SUMMARY

1.1 Background

There are over 990,000 oil and natural gas wells in the U.S., of which approximately 783,000 (79 percent) are considered "marginal" in terms of their profitability to operators, or low production, defined as producing less than 15 barrels of oil equivalent (BOE) per day of combined oil and natural gas. Marginal wells are a significant source of energy for the U.S., currently accounting for 7 to 8 percent of total oil and gas production (EIA, 2020). In 2018 and 2019, the five states with the largest reported numbers of marginal gas wells were Texas, Pennsylvania, West Virginia, New Mexico, and Oklahoma, and the five states with the most reported marginal oil wells were Texas, Kansas, California, Oklahoma, and Louisiana (EIA, 2020).

In recent years, stakeholders have expressed disparate views regarding whether marginal well sites should be subject to or exempt from fugitive emissions monitoring and associated details of the U.S. Environmental Protection Agency's *New Source Performance Standards* (NSPS, 40 CFR Part 60, Subpart OOOOa), which regulate fugitive emissions from new and modified oil and natural gas facilities. Many independent oil and gas producers contend that potentially expensive leak detection and repair (LDAR) requirements could affect all producers but will, in particular, affect small oil and gas operators of marginal wells, with an associated economic impact. Environmental interests have reasoned that frequent monitoring of emissions from marginal production is necessary for the U.S. to achieve critical methane emission reductions. Despite points of disagreement, stakeholders have generally agreed there is a critical need for a substantial body of nationally representative data on marginal well emissions and associated activity factors to support future decisions and rulemaking on this important issue.

1.2 Study Objective and Approach

This project commenced in March 2019 under an Assistance Agreement with the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), with supplemental cost share provided by oil and gas industry partners. The objective of this research was to measure methane emissions from marginal well sites at various basins across the United States. The goal was to collect and evaluate representative, defensible, and repeatable data and draw quantifiable conclusions on the extent of emissions from marginal wells across oil and gas producing regions of the U.S., and to compare these results to published data on the emissions from nonmarginal wells. A Technical Advisory Steering Committee that included stakeholder representation from industry, federal and state regulatory agencies, non-government organizations, and academia was engaged to provide input and feedback on key project activities. The scope of work primarily consisted of the major tasks summarized below, each described further in the main body of this report.

1.3 Regional Field Campaigns

Employed Procedures: Field site selection and all field activities were performed in accordance with procedures detailed in Regional Field Workplans (GSI, 2019b, 2020). Facilities were selected for measurement using geographically clustered, random sampling. All gas emissions were detected using an optical gas imaging camera and quantified, where possible, using a Bacharach Hi-Flow sampler in conjunction with gas composition-specific analyses or downwind measurement methods.

Visited Field Sites: Overall, 589 oil and gas production sites were visited in coordination with 15 participating host operators, who in addition to direct access to perform emission screening and measurements, provided valuable activity data. Among visited sites, 524 exhibited marginal production at an average rate of 2.5 BOE per day of combined oil and natural gas. Sitewide production or throughput was nonmarginal at 65 sites (approximately 11% of the total visited), where production ranged from 15 to 2100 BOE per day. The relatively small size, low equipment counts, and ease of accessibility of most emission sources led to complete screening at all visited sites and complete measurements of most observed emissions. Besides emissions screening and measurements, detailed activity data, including major equipment counts and oil and gas production rates, were documented at each visited site.

Frequency and Magnitude of Detected Emissions: On a sitewide basis, no emissions were detected at approximately 55% of visited natural gas production sites and approximately 60% of visited oil production sites. Overall, emission rate measurements across the entire study exhibit the long-tail behavior commonly observed in air emissions studies. Figure E1 provides additional perspectives on the relative extent and magnitude of methane emissions among key subpopulations of sites. These plots compare distributions of estimated sitewide methane emissions among site populations distinguished by main product (natural gas vs. oil) and region. Approximately 90% of the observed methane emissions were less than 16 standard cubic feet per hour (scfh; 0.25 kg/h or 2.4 tons per year [TPY]), and 95% of the observed emissions were less than 38 scfh (0.60 kg/h, 5.8 TPY). Study wide, the top 10% of emitting sources contributed 90% of the total methane emissions observed. The ten largest observed sources, each emitting between 100 and 780 scfh of methane (1.6-12 kg/h, 15-120 TPY), accounted for 2% of the total measured emissions.

Equipment-Specific Emissions: Separators, wellheads, and tanks were by far the most common equipment encountered for all types of sites and exhibited the largest volumes of emissions. Section 5.3 of this report summarizes the types and numbers of all major equipment encountered at the visited sites, the frequency and magnitude of detected and measured emissions, and applicable emission factors for emitting equipment and full populations of observed equipment consistent with emission factors used in the EPA's Greenhouse Gas Reporting Program (GHGRP).

1.4 Data Analyses

Exploratory Data Analyses: Statistical exploratory data analyses were performed on the results of the regional field campaigns to identify and assess the significance and strength of correlations among key site metadata and the frequency and magnitude of detected whole gas and methane emissions. These analyses indicate that sitewide methane emissions from oil and gas well sites are most strongly correlated with main product type, major equipment counts, and total oil and gas production rate. No other factors, including geologic basin, geologic region, size, age, well type, etc. were found to be as or more strongly associated with frequency and magnitude of sitewide methane emissions.

Among visited field sites, both the frequency of detected emissions and magnitude of methane and whole gas emission rates are most strongly correlated with the sitewide count of major equipment and weakly correlated with site total oil and gas production rate. The frequency of separator emissions is strongly associated with the number of phases of the separator (two or three) in addition to site production rate. Only weak associations were found between emission detection frequency and evaluated characteristics of tanks and wellheads.

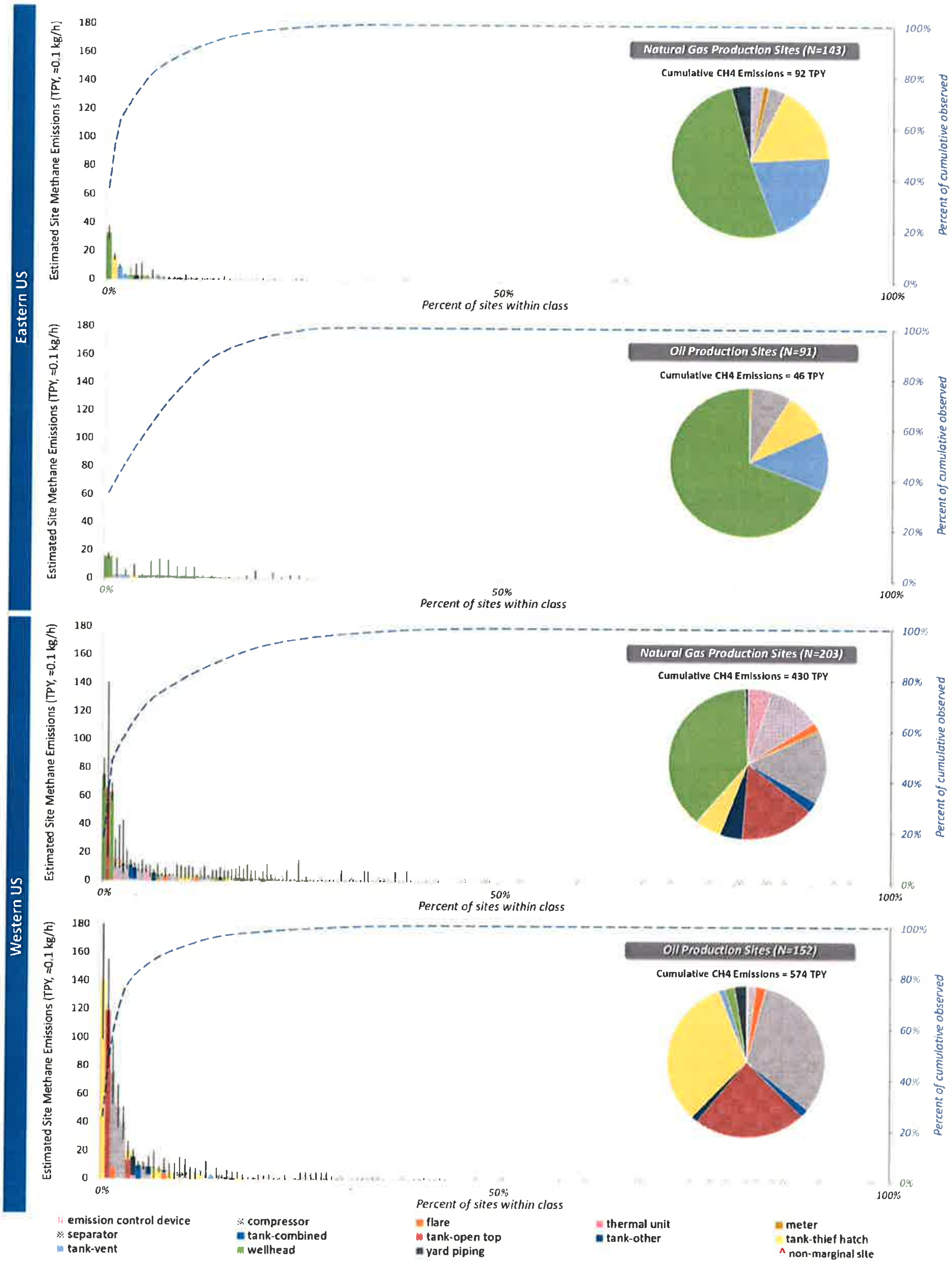


***Figure E1**. Distribution of observed sitewide and equipment-specific methane emissions among visited site subpopulations.*

Production Site Category Emission Profiles: Based on the relative frequency and magnitude of methane emissions observed across all sites visited in the regional field campaigns, applicable emission factors were developed for each of 22 site categories defined and parameterized based on three key distinguishing factors: predominant production type (oil or gas), total oil and gas production rate, and site "size" defined in terms of the total count of major equipment. The upper chart in Figure E2 summarizes the number of visited field sites in each category together with related values on the frequency of detected and measured emissions. The lower chart in Figure E2 summarizes values of two alternate forms of applicable population average emission factors for each site category, one based on absolute emissions per site (left side axis, units of TPY/site) and the other normalized per the total corresponding site oil and gas production (right side axis, units of ton/MBOE).

It is important to recognize that the results of this study correspond only to emissions observed at the time of each site visit and do not include episodic high emission events, such as liquids unloading or manual liquids removal, which were not a key focus of this study and were not observed during the visit to any site. Study-wide, host operators reported that liquids unloading events occurred with varying frequency at 118 of the visited sites.

Relative Magnitude and Extent of Production-Related Methane Emissions: For comparative purposes, state-specific and nationwide estimates of total methane emissions from marginal vs. nonmarginal oil and gas production were developed based on published statewide well counts and production data in combination with key results of this study, including operator-provided activity data from the initial desktop study, the frequency of emissions from key sources, and the magnitude of such emissions based on collected measurements. These estimates account for a wide range and diversity of field conditions, site characteristics, production and equipment types, operational processes, and both permitted and fugitive emission sources observed and documented "as is, where is" at the marginal and nonmarginal production sites visited in the regional field campaigns.

Using both types of average population emission factors shown on Figure E2 for each of 22 discrete categories of production sites, total annual methane emissions were estimated for each oil and gas producing state in the U.S., based on i) the total number of sites in each category times a site count-based emission factor and ii) the total oil and gas production from sites in each category times a production-based emission factor. Considering the combined effects of the multiple sources of uncertainty, Monte Carlo simulations were performed to derive reasonable central, lower, and upper estimates for each state- and category-specific total emission calculation. The resulting annual emission estimates were then summed to yield total statewide and nationwide estimates for key site populations of interest, including marginal vs. nonmarginal gas wells and marginal vs. nonmarginal oil wells. These results are summarized on Table E1 and in Figure E3.

The results of this study suggest that i) marginal oil and gas production in the United States may account for approximately 1 million (±140,000) tons per year (TPY) of "every day" methane emissions, as were observed in the regional field campaigns, ii) marginal gas production accounts for an estimated 60% (±10%) of emissions from U.S. natural gas production, and iii) marginal oil production accounts for an estimated 40% (±10%) of emissions from U.S. oil production.

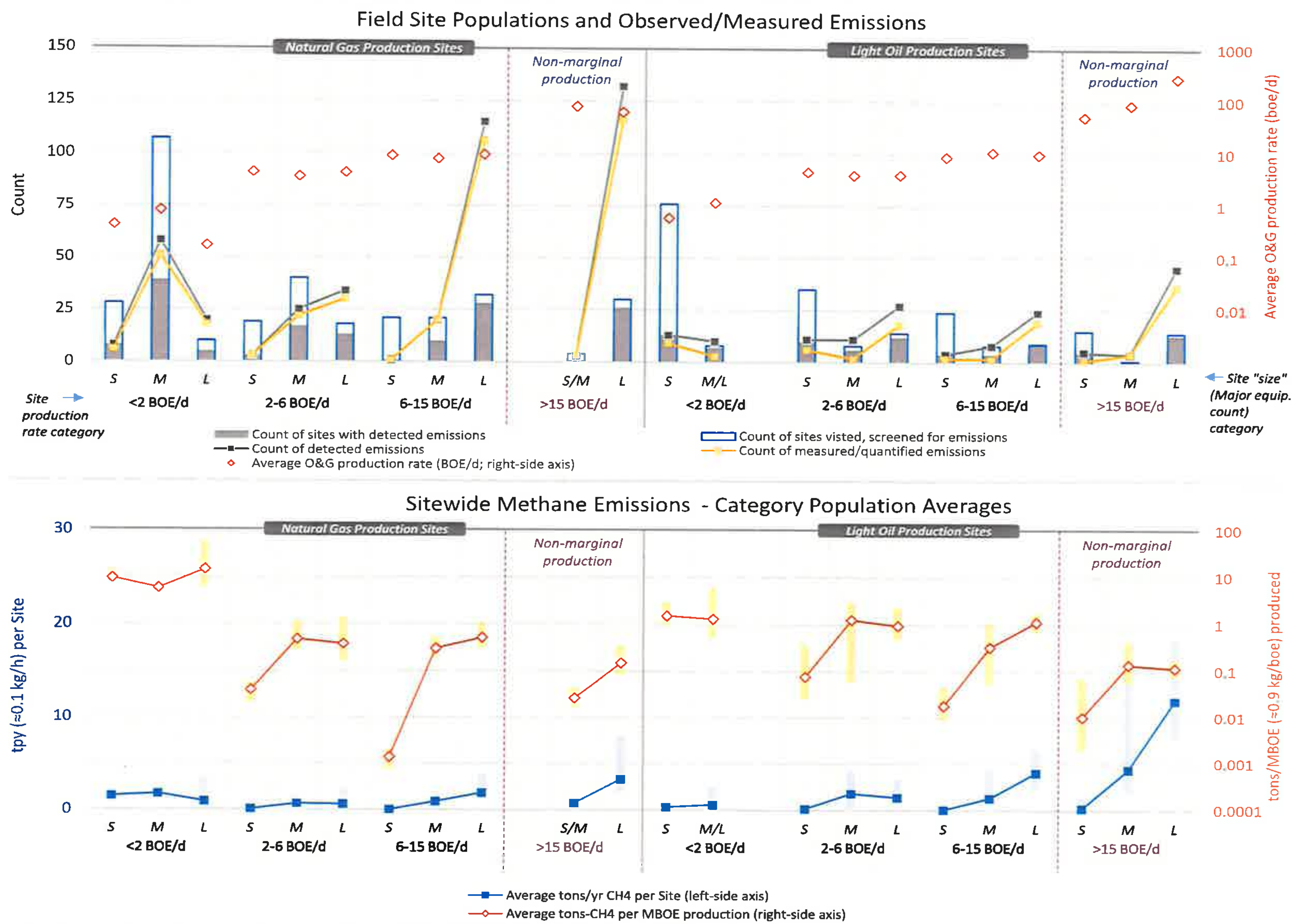


***Figure E2.** Production site category population details and average emission profiles*

Table E1. *Relative Estimated Methane Emissions from Marginal and Nonmarginal O&G Production*

	Approx. Well Count		Annual Production		Estimated Cumulative Methane Emissions			Avg. Pop. Emission Factors	
	count	share	boe/yr	share	ton/yr	Tg/yr	share	tons/yr/well	ton/MBOE
Natural Gas Production									
Marginal	420,000	78%	4.6E+8	7%	640,000 ±80,000	0.58 ±0.08	59% ±12%	1.5 ±0.2	1.4 ±0.2
Nonmarginal	120,000	22%	5.8E+9	93%	450,000 ±170,000	0.41 ±0.16	41% ±12%	3.7 ±1.4	0.077 ±0.030
total gas	*540,000*	*100%*	*6.2E+9*	*100%*	*1,090,000 ±260,000*	*0.99 ±0.23*	*100%*	*2.0 ±0.5*	*0.18 ±0.04*
Oil Production									
Marginal	363,000	80%	3.2E+8	8%	360,000 ±50,000	0.33 ±0.05	37% ±9%	1.0 ±0.1	1.1 ±0.2
Nonmarginal	88,000	20%	3.9E+9	92%	610,000 ±150,000	0.55 ±0.14	63% ±9%	7.0 ±1.7	0.16 ±0.04
total oil	*451,000*	*100%*	*4.2E+9*	*100%*	*970,000 ±210,000*	*0.88 ±0.19*	*100%*	*2.2 ±0.5*	*0.23 ±0.05*
Combined Oil & Gas Production									
Marginal	783,000	79%	7.7E+8	7%	1,000,000 ±140,000	0.91 ±0.13	49% ±11%	1.3 ±0.2	1.3 ±0.2
Nonmarginal	208,000	21%	9.6E+9	93%	1,060,000 ±320,000	0.96 ±0.29	51% ±11%	5.1 ±1.6	0.11 ±0.03
total oil & gas	*991,000*	*100%*	*1.0E+10*	*100%*	*2,060,000 ±460,000*	*1.87 ±0.42*	*100%*	*2.1 ±0.5*	*0.20 ±0.04*

Regionally, the Appalachian Basin appears to generate the largest volume of marginal production-related methane emissions from any single geologic basin, with an estimated 290,000 TPY coming from Pennsylvania, West Virginia, and Ohio, New York, Maryland, and Virginia representing 29% of methane emissions from US marginal oil and gas production. Texas, Oklahoma, and New Mexico, which encompass the Permian Basin plus large parts of the Anadarko, San Juan, and other basins, together emit an estimated 380,000 TPY of methane.

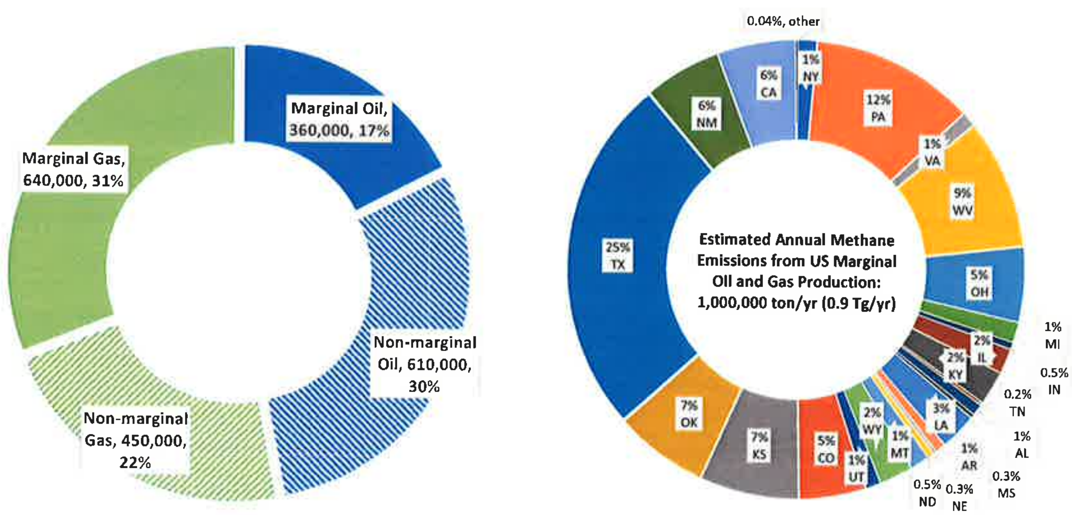


Figure E3. *Relative estimated methane emissions from marginal and nonmarginal O&G production.*

2.0 PROJECT OVERVIEW

2.1 Background

There are over 990,000 oil and natural gas wells in the U.S., of which approximately 783,000 (79 percent) are considered marginal in terms of their profitability to operators, or low production, defined as producing less than 15 barrels of oil equivalent (BOE) per day of combined oil and natural gas. Similarly, wells producing less than 10 BOE per day are commonly referred to as "stripper wells". Marginal wells currently account for 7 to 8 percent of total U.S. oil and gas production (EIA, 2020; IOGCC, 2016).

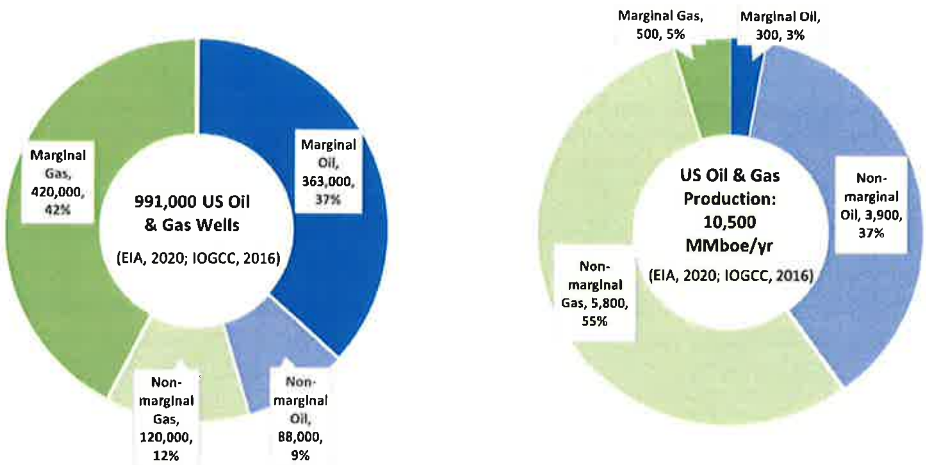


Figure 1. *Current estimated US marginal well population and production.*

In recent years, stakeholders have expressed disparate views regarding whether marginal production operations should be subject to or exempt from fugitive emissions monitoring and associated details of the U.S. Environmental Protection Agency's New Source Performance Standards (NSPS, 40 CFR Part 60), which regulate fugitive emissions from oil and natural gas facilities. (Subpart OOOOa and proposed Subpart OOOOb apply to new, modified, or reconstructed sources, and proposed Subpart OOOOc will apply to existing sources.) Industry research has found that expensive LDAR requirements could preclude potentially decades of continued production from many marginal wells, whose limited profitability already depends on the fluctuating oil and gas market (IOGCC, 2016; Bluestein, 2015). Despite their relatively low production volume, limited earlier research suggested that marginal gas production may be responsible for over 50% of all methane emissions from the U.S. natural gas production segment (Omara et al., 2018).

2.1.1 Federal Regulation of Fugitive Emissions from Oil and Natural Gas Production

The EPA first required semiannual leak monitoring at marginal production sites in June 2016, with amendments to the NSPS, Subpart OOOOa, to reduce fugitive methane emissions from new and modified oil and natural gas facilities. In 2017, EPA granted reconsideration on the applicability of the fugitive emissions requirements to low production well sites. In 2020 EPA rescinded fugitive monitoring requirements for marginal well sites and retained semiannual monitoring for nonmarginal wells. The EPA released information on newly proposed methane emissions regulations on November 15, 2021.

2.1.2 State vs. EPA Fugitive Emissions Monitoring Requirements

Regulations in several states appear to incorporate federal NSPS requirements by reference. These include Kansas, Oklahoma, and West Virginia. In April 2018, during NSPS rulemaking, the EPA analyzed and summarized the requirements of various state fugitive emissions programs for well sites. They compared each state program's requirements to proposed revisions to the NSPS for the oil and natural gas sector (EPA, 2018). This analysis revealed many complexities and nuances of the state programs, which made them very difficult to compare qualitatively. While many differences were noted, EPA concluded that the fugitive emissions requirements related to monitoring, repair, and recordkeeping for California, Colorado, Ohio, Pennsylvania, Texas, and Utah were "equivalent" to those of the NSPS amendments proposed at the time. EPA noted it was unable to determine the equivalency of requirements in Montana, New Mexico, North Dakota, and Wyoming.

In response to EPA's findings, analysts with the Environmental Defense Fund performed an independent comparison in addition to a quantitative analysis accounting for (among other factors) differences in the required timing to repair detected leaks to assess the efficacy of state LDAR requirements to meet specified target methane emissions reductions relative to requirements of both the 2016 NSPS and 2018 proposed amendments. Based on their analysis, they concluded that the existing programs in California and Colorado would outperform the 2016 NSPS requirements in achieving methane reductions, and only these states plus Ohio would outperform requirements of the 2018 proposed amendments (McVay and Roberts, 2018).

2.2 Study Objective and Approach

The objective of this research is to measure methane emissions from representative marginal well sites at various basins across the United States. The goal is to collect and evaluate representative, defensible, and repeatable data and draw quantifiable conclusions on the amount of emissions from marginal wells across oil and gas producing regions of the U.S., and to compare these results to published data available on the emissions from nonmarginal wells. The major sections of the scope of work are summarized below.

- ***Data Source Status Assessment and Master Workplan***: At the onset of the project, key data gaps were identified based on a thorough review of published sources and partially addressed by information derived from a survey of oil and gas well operators for representative production site data across the U.S. This information guided development of a master workplan to establish and document necessary site and technology selection criteria and the overall approach for field data collection, evaluation, and reporting.

  Data for over 80,000 marginal wells were collected in the initial operator survey, 17% of which represented oil wells and 83% gas wells. These numbers equal about 4% of the marginal oil wells and 16% of the marginal gas wells in the U.S. reported by EIA (2020) and IOGCC (2016). Survey responses covered most regions of the country where marginal wells are reported, with notable exceptions being California (where over 40,000 marginal oil wells are reported by EIA) and eastern portions of the Gulf Coast Basin (nearly 8,000 wells in Mississippi and Alabama). Also of note, responses for New Mexico only represented wells in the Permian and not the San Juan Basin (Four Corners area), and responses for Arkansas only represented gas production and no oil production. Overall oil and gas production rates from the operator survey averaged, overall, 1.9 bpd of oil and 13.6 MCFD for gas, which compare very favorably to the average production rates of 2.0 bpd and 13.5 MCFD, reported by IOGCC (2016), and estimates of 2.4 bpd and 17.9 MCFD, based on more recent data from EIA (2020). This suggests the survey data are, in general, representative of national trends with respect to production.

- ***Regional Field Campaigns:*** Between October 2019 and June 2021, methane emissions were screened and measured, where detected, at 524 marginal and 65 nonmarginal oil and gas production sites across multiple U.S. regions and geologic basins. The ultimate objective of these campaigns included capturing the variability and diversity of both physical and operational conditions, especially in areas with large numbers or a high density of marginal wells, or where marginal wells account for a substantial percentage of regional production.
- ***Data Processing, Analysis and Reporting***: Exploratory and statistical data analyses of the comprehensive study dataset were performed to identify key groupings of sites in the studied regions and their distinguishing characteristics and emission profiles. Results were applied to establish site populations to extrapolate and compare nationwide and regional/state-specific estimates of total methane emissions from marginal vs. nonmarginal oil and natural gas production sites across the U.S., including regions not visited in the regional field campaigns.

3.0 REGIONAL FIELD CAMPAIGNS

All of the regional field campaigns were conducted between October 2019 and June 2021, including emissions screening and measurements by scientists with GSI and the Colorado State University (CSU) Energy Institute using the METEC mobile laboratory (see https://energy.colostate.edu/metec/). Based on the frequency of marginal well sites reported in the earlier operator survey responses, the field campaigns were designed to prioritize locations with dense populations of marginal well sites.

3.1 Visited Field Sites

Overall, 589 oil and gas production sites were visited in coordination with 15 participating host operators, who in addition to direct access to perform emission screening and measurements, provided valuable activity data. Site visits were performed in the Appalachian, Forest City, and Illinois Basins, collectively referred to as the "Eastern US" in subsequent descriptions, and the Anadarko, Permian, Piceance, and Upper Green River Basins, collectively referred to as the "Western US" in subsequent descriptions. Field site selection and all field activities were performed in accordance with procedures detailed in regional field workplans (GSI, 2019b, 2020). Regulatory compliance was demonstrated through the issuance of all necessary permits and National Environmental Policy Act (NEPA) approval.

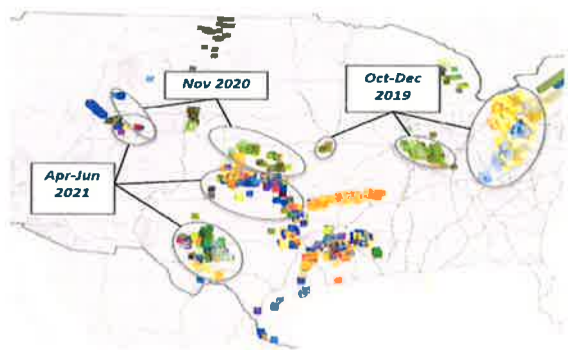


Figure 2. *General locations and times of regional field campaigns.*

Over the course of the field campaigns, a diversity of well design, product separation, and storage configurations encountered contributed to an evolving definition of a "site", with the focus being on collecting data from localized clusters of equipment in close proximity and specifically related to production of a previously identified target wellhead. Thus, a site could include multiple wellheads, while other sites could contain production-related equipment only, such as locations where separation was performed at a central tank battery servicing multiple wells. Such sites were classified as marginal if the total production for all wells sending product to the battery was <15 BOE/d. Figure 3 shows the distributions of total site production rates among visited "natural gas sites" and "oil sites". The classification of a given site was determined simply by the predominance of either oil or gas production in terms of BOE per day.

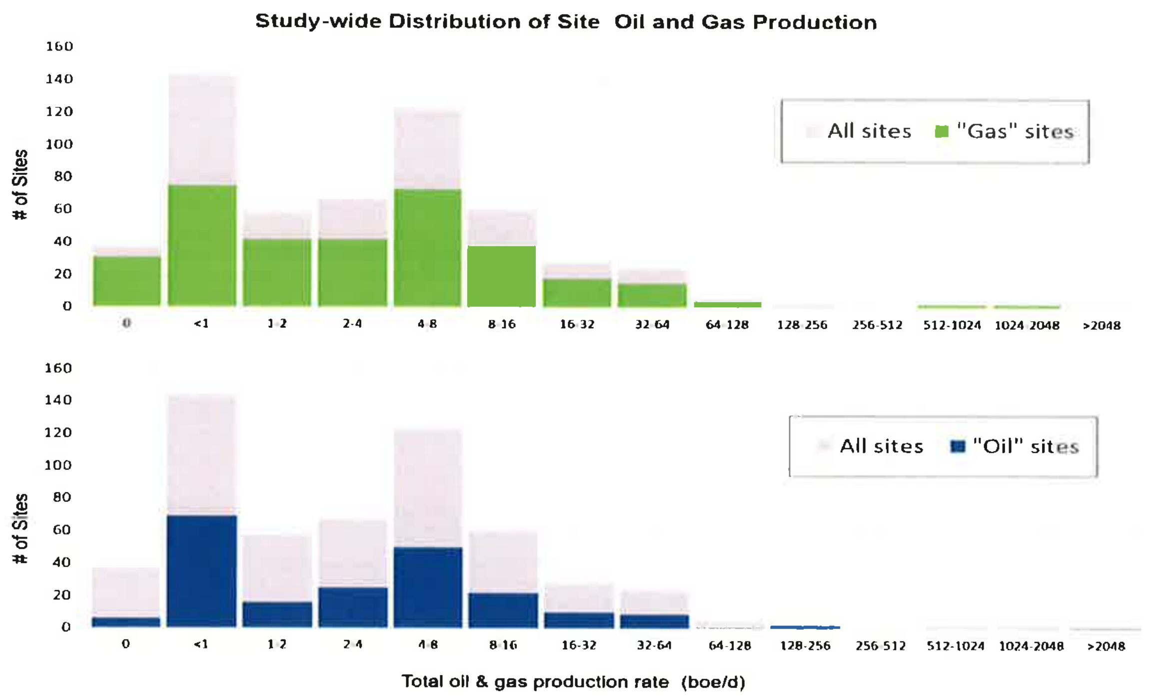


Figure 3. *Study-wide distribution of oil and gas production at visited sites. Sites with total production <15 BOE/d are considered marginal.*

3.2 Field Site Selection

Field sites were selected for measurement using geographically clustered, random sampling. While actual field sites were chosen at random, the initial selection of candidate site clusters was iterative and, to the extent practical, sought to reasonably represent the larger regional and national populations of marginal production sites, maximize the number of facilities visited, and minimize potential biases.

Prior to embarking on each field campaign, target clusters of candidate sites were selected by the research team from region-wide lists provided by each host operator or obtained independently by the research team from a publicly available database. With all operators, candidate site identification was a cooperative and collaborative process largely driven by the research team; therefore, any potential for bias due to so-called volunteer effects is considered low. In the case of large operators, regional candidate site lists included hundreds or, in some cases, many thousands of potentially accessible locations. These were provided by company database managers rather than site managers or environmental personnel. Per agreement with every host, the research team understood all candidate site lists to be fully representative of each operator's marginal production assets in each target region and, most importantly, that the operator would neither limit nor direct access to potential field site in any way that could bias the results of this study.

Figure 4. Daily site selection example. "A", "B", and "C"-sites (red, green, and blue dots, respectively) were chosen at random for measurement. Measured sites are noted with red circles.

Each day of field sampling was dedicated to a specific cluster of sites with a specific operator. Daily short lists of target field sites were chosen at random by the field team no more than a day in advance of being visited for emissions screening and measurement. This tiered and randomized approach to site selection sought to ensure the integrity of the study results by providing minimal advance notice to operators as to which sites would be visited.

For clusters with more sites than could be visited in a day, the following strategy was used. Sites were randomly selected and rank-ordered as "A", "B", or "C"-sites, which correspond to red, green, and blue dots, respectively, as shown in Figure 4. A-sites were the preferred sites to be visited, then B-sites. C-sites were generally not visited. In rare cases, exceptions were made to this strategy for logistical reasons. For example, if there was time to visit one more site in a day and the next A-site on the list was an hour drive away, a nearby B-site would be visited oppurtunistically to maximize the number of site visits for that day. For clusters with fewer sites, all sites within the cluster were screened.

3.3 Emissions Screening and Measurement

The field investigation team was equipped with a variety of equipment and instrumentation, deployed using various methods, to detect and quantify methane emissions typical of oil and gas operations. Optimal screening and measurement methods were chosen at each site to best capture emissions, considering site-specific circumstances, instrumentation or method limitations, and operator safety. All gas emissions were detected using an Opgal "Eye-C-Gas" 2.0 optical gas imaging (OGI) camera and quantified, where possible, using a Bacharach Hi-Flow Sampler (BHFS) that was specially modified to enable canister samples to be drawn from the inlet flow stream, as shown in Figure 5.

Figure 5. Emissions identified using OGI and quantified by BHFS.

Canister samples were drawn for a subset of Hi-Flow measurements and were analyzed for gas species composition by a third-party laboratory. Canister samples were taken for 249 of 460 Hi-Flow measurements to provide insight into typical gas compositions and provide a means for correcting Hi-Flow sensor response variation due to gas composition changes from calibration gas. Multiple samples were not drawn for measurements with a common (or similar) source or if the gas composition did not change at the facility. Instead, the first sample drawn was considered representative. For example, multiple emissions on a common gas feed would rely on the same gas composition sample for correction. Multiple samples were taken when the gas composition was expected to differ significantly. For example, an emission on a wellhead and a tank would require two samples. Further details of the procedure to derive corrected whole gas, methane, and VOC emission rates relative to BHFS instrument readings in the field are discussed in Appendix A.

Additionally, with the METEC mobile laboratory, downwind techniques were available to quantify emissions not suitable for direct measurement with the BHFS, such as due to inaccessibility, high magnitude, or gas composition. Downwind measurements were used to measure large emissions, such as from a tank battery, or where the H_2S content of the field gas presented a safety concern and prevented an attempt at direct measurement. The OTM33a or tracer methods were utilized to quantify 39 emissions which would not have otherwise been measurable due to their size or accessibility. For each of these emissions, only methane was quantified due to the capabilities of the method. Details of the procedures to collect and analyze downwind measurements are discussed in Appendix A.

Among 614 discrete emissions observed at 253 sites, a total of 112 emissions detected at 77 sites were not successfully measured due either to i) malfunctions of the measurement equipment, ii) the emissions not being safely accessible and too small to measure with downwind techniques or, iii) in one case, a host escort closing an open valve before the emission could be measured. All emissions that were identified but not measured are noted and flagged in the field data measurement results. Upon review of the field notes, an additional 13 field measurements with the high flow sampler did not satisfy applicable quality control criteria and were disqualified from use.

Based on OGI recordings of the unquantified emission sources and general observations of the site and equipment operations, these emissions appeared to be "typical" and are expected to fall within the distribution of other observed and measured emissions from comparable emission sources, as characterized in this study. Consequently, for purposes of evaluating statistical population distributions and completeness in estimating values such as total sitewide emissions, detected but unmeasured emissions were accounted for and represented, where needed, by the median emission rate for the corresponding type of equipment in the same U.S. region and, where possible, the same component type. For example, if no qualified measurement is available for an emission observed from a valve on a separator in West Virginia, that emission was represented, as needed, in subsequent analyses by the median of all qualified measurements of valve emissions from separators elsewhere in the Eastern US.

3.4 Site Activity Data Collection

Detailed activity data was documented at each visited site, including oil and gas production rates, major equipment counts, and a general functional description of site processes and activities. Additional data pertinent to understanding any individual measurement, including weather and operating conditions at the time of sampling, and the type and level of fluids in tanks, etc., were also recorded to the extent available.

During each site visit, the host operator representative (usually the site pumper) escorting the sampling team was also "interviewed" to characterize the nature and representativeness of conditions observed during the visit versus at other times, i.e., the expected variability in site conditions with respect to the potential for site emissions. Due to many variations in site layouts, production methods, and equipment types, the host escorts proved invaluable in assisting the field team to recognize and understand many nuances in site conditions and in identifying many different types of equipment, specific components, and relationships among sites, such as product flow from one well pad to a tank on another well pad. Most host operators provided production rate data for each visited site; however, in some cases none was provided or was independently obtained by the research team for a period including up to 1 year prior to the time of the field visit.

4.0 DATA PROCESSING AND ANALYSIS

Upon completion of each field campaign, all collected field notes, photos and recorded OGI video, operator-provided activity data, and emissions measurement data were compiled, archived, checked, and synthesized into a comprehensive project database. Photos and videos from the OGI camera were reviewed to verify the equipment and component type assigned to each emission. All database entries were double checked for accuracy, and all emissions measurements were validated, assessed for usability for further analysis, and either accepted or rejected in accordance with applicable quality assurance/quality control (QA/QC) criteria.

Data analyses were performed on the complete regional field campaign dataset to identify and compare potentially distinct populations of marginal/low producing oil and gas production sites in the studied regions with regard methane emissions and their distinguishing characteristics and emission profiles. For statistical analyses, all data variables were evaluated as either numeric, categorical, or both. For example, in addition to considering exact counts of specific types of equipment as strictly numerical variables, a categorical proxy of site "size" (small, medium, large, etc.) in terms of total major equipment counts facilitated evaluation of a wider range of variable site conditions. Similarly, a series of oil and gas production rate bins was utilized and evaluated as a categorical variable in an effort to reduce the effects of potential unknown inaccuracies or uncertainties in reported production rates. Through the course of exploratory and subsequent data analyses, some of the data were iteratively grouped, divided, and regrouped into relevant categories and subcategories in efforts to identify, characterize, or distinguish significant relationships or findings among the emissions and activity data.

4.1 Exploratory Data Analysis

Statistical exploratory data analyses sought to identify and assess the significance and strength of possible correlations among:

i) Key metadata associated with various characteristics and conditions associated with each visited site, detected and measured emissions, observed equipment, and operational conditions, as documented in the regional field campaigns.
ii) the frequency of detected emissions among visited sites and observed equipment.
iii) the magnitude of qualified methane emissions measurements.

For exploratory purposes, the field site and emissions measurement data and related metadata were sorted, grouped, and evaluated according to two principal subsets: sitewide emissions and equipment specific emissions. Key site factors included the main product type (oil or gas), production rates of oil, gas, and water, frequency of operations, major equipment counts, well or equipment age and condition, region, and operator. A Spearman's Rank Correlation was used to assess correlations between numeric variables, and a Chi-Squared Test or a Fisher Test (depending on the sample size of the compared dataset) was used to assess the independence of categorical variables. In each case, a p-value of 1% was selected to reject the null hypothesis that any two compared variables are independent. In other words, any test with a p-value less than or equal to 1% indicated the compared variables are not independent and, thus are associated or potentially correlated. For interpretation, the relative strength of association among variables compared using either method was characterized consistently on a scale of 0 to 1 as weak (0.0-0.39), moderate (0.40-0.59), or strong (0.6-1.0) based on the Spearman rank order coefficient (rho) or, for Chi-Squared tests, a normalized primary test statistic. Results of these analyses are discussed in the following section, and additional details on related data evaluation procedures, criteria, and results are presented in Appendix B.

4.1.1 *Sitewide Emissions Analysis*

Analyses of sitewide emissions separately considered the detection of one or more emissions at any type of equipment, the frequency of emissions expressed as the number of detected emissions divided by the total pieces of equipment at a site, and the total magnitude of methane and whole gas emissions at all sites where 100% of detected emissions were successfully quantified. Importantly, the analysis of site emission detection frequency did not look solely at the absolute emission count (i.e., where one would logically expect the presence of more equipment to correlate with a higher frequency of emissions.) The factors most strongly correlated with sitewide methane emissions are discussed in Section 5.2.1.

4.1.2 *Equipment Emissions Analysis*

Evaluation of equipment emissions specifically focused on the three most prevalent types of equipment encountered: wellheads, separators, and tanks, which in all of the studied regions were fairly ubiquitous among both oil and gas well sites. These also represent the largest and most frequently observed sources of emissions in all regions. At gas well sites, only meters were encountered with a similar frequency; however, those exhibited relatively few emissions (<3% frequency study wide). Factors considered for wellheads, separators, and tanks included host operator, site production status (active, inactive, shut-in, etc.), basin/region, primary product, oil and gas production rates, and production frequency. Other factors were specific to the equipment characteristics. Tank emissions were evaluated against the quantity of hatches and vents, whether tank vents were atmospheric or pressurized, and the fluid level of the tank while onsite (fullness). Wellhead emissions were evaluated against variables such as the presence of casing vents, well age, well depth (where pressure of the production formation could relate to casing head pressure), artificial lift type, and whether the well was producing brine. Separator emissions were evaluated against variables such as separator age, the number of phases it was designed to separate, maximum design pressure, and operational pressure.

4.2 Emissions-Based Site Category Characterization/Classification

As part of the initial desktop study, a series of site characteristics likely to contribute substantially to overall site-level methane emissions was identified, and related classification criteria were defined to support site selection for the regional field campaigns. These were intended to capture the variability of characteristics encountered among low producing oil and gas well sites throughout the continental US in terms of main product, total oil and gas production rate, and site "size" defined in terms of a total count of major equipment.

As discussed further in the next section, analysis of the results of the regional field campaigns and subsequent data analysis indicate that sitewide methane emissions from oil and gas well sites are indeed most strongly correlated with main product type, major equipment counts, and production rate. No other factors, including geologic basin, geologic region, size, age, well type, etc. were found to be as or more strongly associated with frequency and magnitude of sitewide methane emissions. Based on the relative frequency and magnitude of methane emissions observed across all sites visited in the regional field campaigns, with respect to sitewide emissions the results of this study were evaluated in terms of classification categories defined and parameterized as shown on Table 1.

Table 1. *Production Site Classification Criteria for Methane Emissions Characterization and Estimation*

Parameter	Categories			
Main Product	Natural Gas		Oil	
Production Rate (BOE/day/site)	0-2	>2-6	>6-15	>15 (nonmarginal)
Well Pad Size (Pieces of equipment)	Small (1-2)	Medium (3-5)	Large (6+)	-

All possible combinations of these criteria would give rise to 24 distinct categories. However, across all of sites visited in the regional field campaigns, only one "large" oil site producing <2 BOE/d and no nonmarginal gas sites with fewer than 3 pieces of equipment were visited. For purposes of subsequent data analyses and representation of results, these categories were combined with adjacent categories relative to the size criterion. Figure 6 summarizes the breakdown of field site populations for the resulting 22 site categories and related figures on the frequency of emissions detections and measurements.

4.3 National and Regional Methane Emissions Estimates

For comparative purposes, state-specific and nationwide estimates of total methane emissions from marginal vs. nonmarginal oil and gas production operations were developed based on published statewide well counts and production data in combination with key results of this study, including operator-provided activity data from the initial desktop study, the frequency of emissions from key sources, and the magnitude of such emissions based on collected measurements. These estimates account for a wide range and diversity of field conditions, site characteristics, production and equipment types, operational processes, and both permitted and fugitive emission sources observed and documented "as is, where is" at the marginal and nonmarginal production sites visited in the regional field campaigns.

Based on the geographic extent and range of sites characteristics reported in the operator data survey and judicious design and planning of the regional field campaigns, the sites visited and conditions observed in this study are believed to substantially represent the full range of "every day" conditions and emissions one can expect to encounter in the course of typica LDAR inspections or other fugitive emissions monitoring at most onshore oil and gas production facilities anywhere in the U.S. However, it bears emphasizing that sources of a potentially large fraction of *all* production-related methane emissions, including, in particular, liquids unloading at natural gas wells or other potentially high-emitting episodic events, were neither the focus of this study nor encountered at any visited site. Consequently, use of the word "total" in this report to describe emissions on a sitewide, statewide, or nationwide basis, should be understood to mean "sum" or "aggregate" in the context described above, rather than "all."

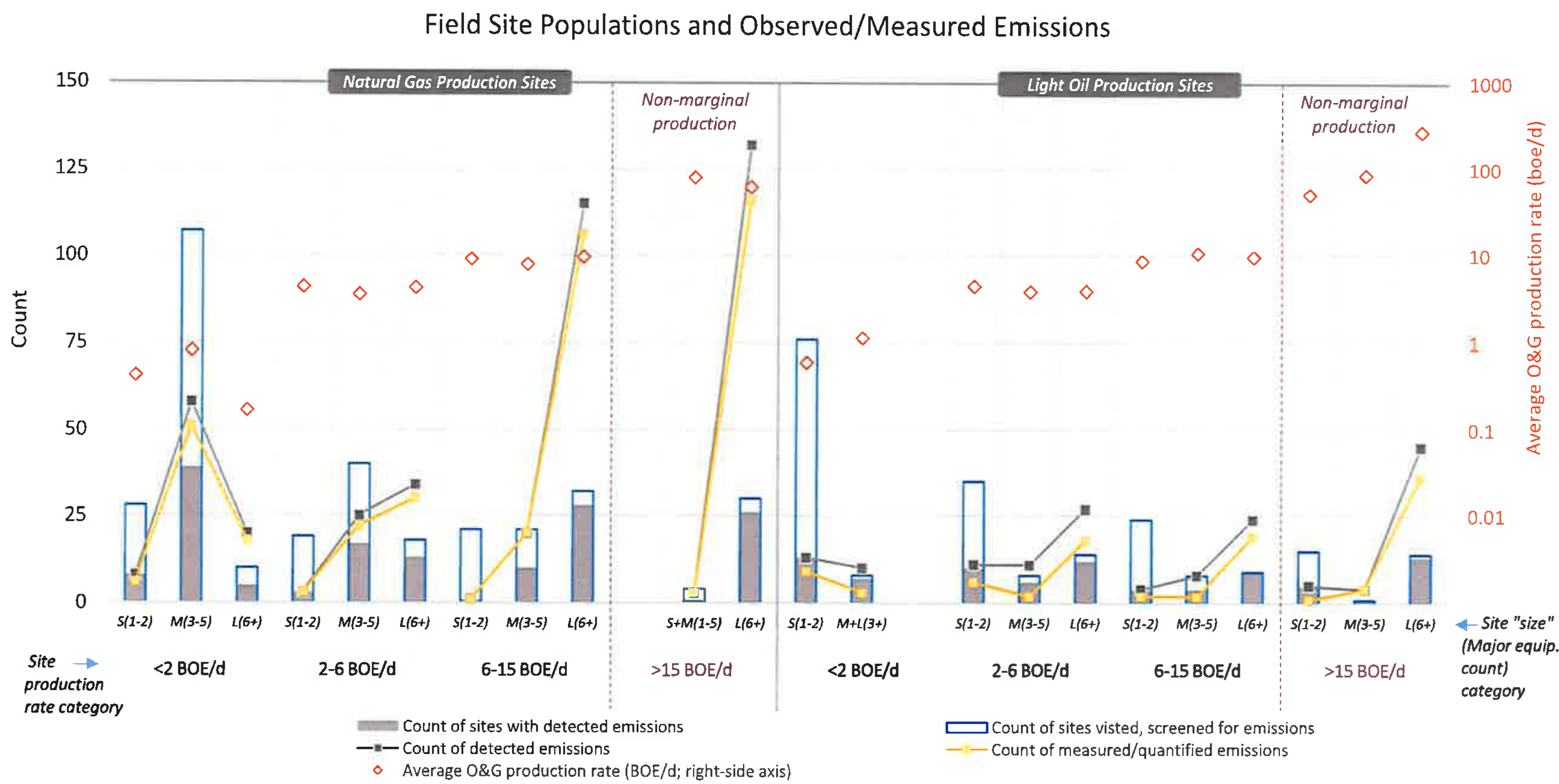


Figure 6. *Field site populations and emission detection/measurement frequency for emissions-based site categories. Similar field sites were sorted into groups based on sitewide production rates and equipment counts, as detailed on Table 1.*

State-specific well count and production rate data, sorted by production rate category, were obtained from a U.S. Energy Information Administration database (EIA, 2020) for all oil and gas producing states except Indiana and Illinois. Comparable well counts and production rate distributions for Indiana and Illinois were derived from information published by IOGCC (2016) in addition to data for sites in those states represented in the operator survey database. For all states, the categorization of sites according to "size" (i.e., major equipment count) was primarily based on corresponding distributions of site size represented in the operator survey database, as neither the EIA database nor the IOGCC data reflect differences in this parameter. This assumption is subject to a high degree of uncertainty, however, as some states are not represented in the survey database, and the survey results may not accurately reflect the actual distribution of site sizes in some states. The handling of these and other uncertainties in this analysis is discussed further below.

Based on the classification criteria listed on Table 1 and applicable emission factors for the 22 site categories delineated in Figure 6, total annual methane emissions were estimated for each oil and gas producing state, based on i) the total number of sites in each category times a site count-based emission factor and ii) the total oil and gas production from sites in each category times a production-based emission factor. The resulting annual emission estimates for each category were summed and averaged, as appropriate, to yield statewide, regional, and nationwide total estimates for key site populations of interest, including marginal vs. nonmarginal gas wells and marginal vs. nonmarginal oil wells. The applicable emission factors used in these calculations are discussed in Section 5.2.2, and the values of those emission factors and related ranges of measurement uncertainty are presented on Table 4. An additional source of uncertainty evaluated in these calculations arises from the highly skewed distribution of measured emission rates (see Figure 7), which form the basis of the applied emission factors, and the possibly that a similar or even more highly skewed distribution exists among emissions that were detected but not successfully measured in the regional field campaigns.

The combined effects of the three sources of uncertainty described above were addressed by employing a Monte Carlo model to derive reasonable central, lower, and upper estimates for each state- and category-specific total emission calculation. The sensitivity of these estimates to a potentially highly skewed distribution of detected but unmeasured emissions was assessed by additional simulations. For each Monte Carlo simulation, 10,000 iterations were performed, varying a series of uniformly distributed random variables considering i) alternate reasonable state-specific assumptions regarding the distribution of site sizes, ii) the full range of measurement uncertainty associated with each applicable site category emission factor, and iii) alternate assumptions of moderate vs. high skewness in the rates of detected but unmeasured emissions in the regional field campaigns. The results of this analysis are presented and discussed in Section 5.4.

5.0 RESULTS AND DISCUSSION

5.1 Emissions Measurement Results

In Figure 7, plots of the 498 study-wide measured emission rates exhibit the long-tail behavior commonly observed in air emissions studies. In this study, approximately 90% of the observed methane emissions were less than 16 scfh (0.25 kg/h, 2.4 TPY) and 95% of the observed methane emissions were less than 38 scfh (0.60 kg/h, 5.8 TPY). Study wide, the top 10% of emitting sources contributed approximately 90% of the total methane emissions observed.

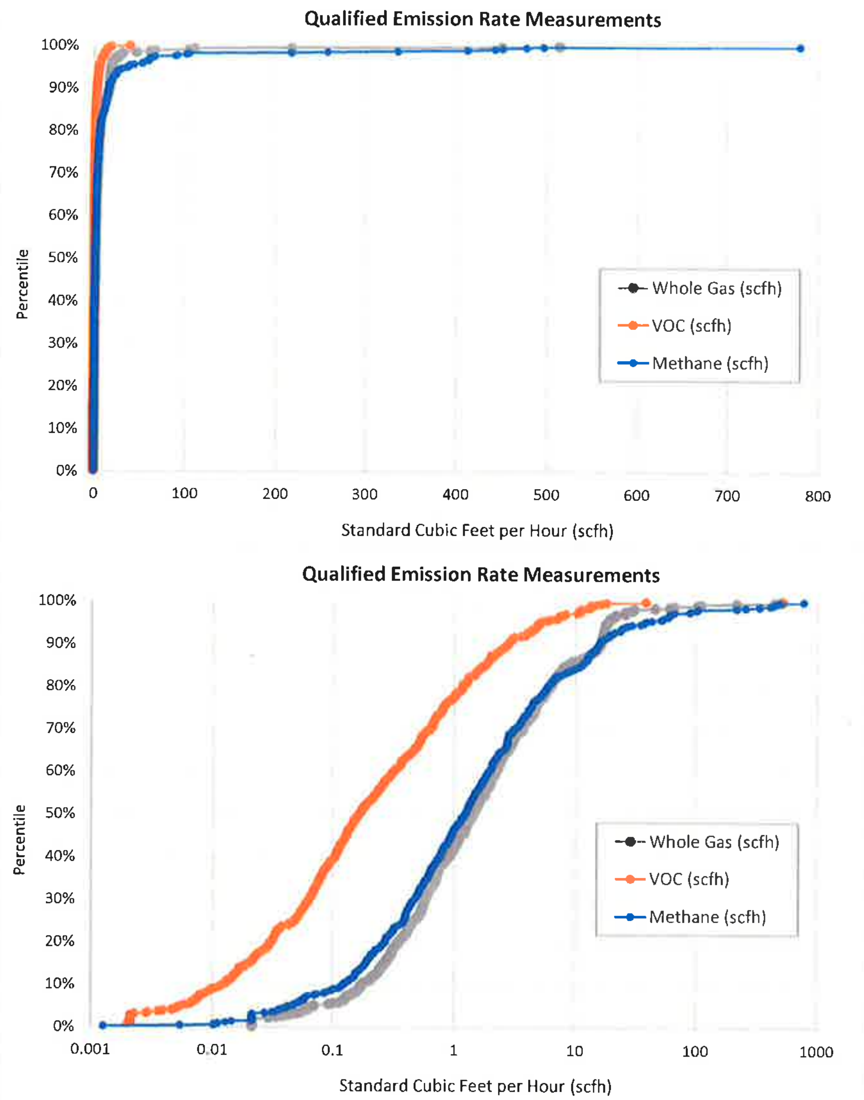


Figure 7. *Long-tail behavior observed in the study-wide measured emission rates. A small number of the emitters contributes a large portion of the emissions.*

Table 2 summarizes details of the 10 largest emissions measured among 613 emissions detected in the studied regions. Notably, four of these are related to general operational conditions, including the largest emission of 780 scfh (12 kg/h; 120 TPY) coming from an open top produced water tank, which accounted for 12% of study-wide observed methane emissions. Two corresponded to valves left open to allow wellhead surface casings to vent, and another to an open hole on the side of a well casing. Another eight emissions, ranging in magnitude from 2 to 90 scfh (0.0003 to 1.4 kg/h; 0.003 to 14 TPY) appeared related to general operation conditions or human factors rather than leaking or malfunctioning equipment.

Table 2. Top 10 Largest Observed Emissions

Rank	Methane Emission Rate (scfh)	(kg/h)	(tpy)	Emission Location	Emission Location Detail	Basin	Region2	Mech. or Oper. Issue?	Notes	Site type; Major equipment present
1	780	12	118	Tank	Produced water tank	Permian	Western US	Operational	open top tank	Nonmarginal oil, 1 wellhead, 6 separators, 9 tanks
2	499	7.8	76	Wellhead	Surface casing valve	Permian	Western US	Operational	open valve on wellhead	Marginal gas, 1 wellhead, 1 tank
3	486	7.6	74	Tank	Thief hatch	Permian	Western US	Mechanical	failing pressurized vent	Marginal oil tank battery, no wellhead, 2 separators, 1 meter, 4 tanks (2 emissions on separate tanks at same site)
4	460	7.2	70	Tank	Thief hatch	Permian	Western US	Mechanical	failing pressurized vent	
5	442	6.9	67	3-phase Separator	Water dump valve	Permian	Western US	Mechanical	malfunctioning pneumatic device	Nonmarginal oil "satellite", no wellhead, 4 separators, 2 meters, no tanks
6	437	6.9	66	Wellhead	Surface casing valve	Permian	Western US	Operational	open valve on wellhead	Marginal gas; 1 wellhead, 1 meter, 1 separator, 1 tank
7	337	5.3	51	3-phase Separator	Water dump valve	Permian	Western US	Mechanical	malfunctioning pneumatic valve	Nonmarginal oil "satellite", no wellhead, 3 separators, 3 meters, 1 compressor, no tanks
8	258	4.0	39	3-phase Separator	Water dump valve	Permian	Western US	Mechanical	malfunctioning pneumatic valve	Nonmarginal oil "satellite", no wellhead, 2 separators, 2 meters, no tanks
9	186	2.9	28	Wellhead	Surface casing	Appalachian	Eastern US	Operational	open hole on side of surface casing	Marginal gas, 1 wellhead, 1 meter
10	106	1.7	16	Wellhead	Sucker Rod Packing	Forest City	Eastern US	Mechanical	rod leaking during pumping	Marginal oil, well only

5.2 Total Emissions by Site

The precise definition and classification of an oil or natural gas production "site" proved challenging and could be subjective. For purposes of this study, the designation of a "site" generally denotes all equipment located together at a single contiguous well pad or physical location. During the field campaigns several locations were visited where multiple wells sharing a common tank battery were located relatively close to one another, but not on the same well pad (e.g., 20 wells spaced hundreds of feet apart over a 100-acre area). For purposes of data analysis, such locations were classified and counted separately as "small" sites due to a greater similarity of their characteristics with many other well-only sites visited, compared to "large" sites, where multiple wells were located on a single well pad. If the flow of production from a single wellhead continued offsite to a set of separators or tanks collecting fluid and/or gas from multiple wellheads on multiple pads, the pad and separation station sites were considered related, but separate.

5.2.1 Factors Most Strongly Correlated with Sitewide Methane Emissions

As noted above and described in detail in Appendix B, exploratory data analyses showed both the frequency of detected emissions and magnitude of methane and whole gas emissions among visited field sites to be most strongly correlated to the count of major equipment and secondarily correlated with site total oil and gas production rate. The correlation between major equipment count and site emission frequency (expressed as the number of detected emissions per piece of major equipment, i.e., not absolute count of emissions), was strong with the categorical site "size" variable and moderate (positive) with the numeric equipment count.

Among evaluated numeric variables, site equipment count also exhibited the strongest associations with both frequency and magnitude of sitewide emissions, exhibiting only a moderate positive correlation with detection frequency and weak associations with whole gas and methane emission rates. Weak correlations were also consistently detected among both the frequency and magnitude of emissions, total oil and gas production, and gas production rates.

5.2.2 Production Site Category Emission Profiles

Emission rates and factors can be considered in different ways, including: i) in absolute terms of the volume or mass of emissions per unit time, and ii) normalized relative to the rate of gas or oil produced in conjunction with a given emission. The latter of these can be considered a metric of methane intensity. In Figures 8 and 9, methane emission profiles in terms of both of these types of emission factor are compared among the 22 site categories shown in Figure 6. As described in Section 4.2, each category is characterized by a unique combination of production type (gas or oil), site size (in terms of major equipment count), and production rate bin. Additional details are presented on Table 4.

Figure 8 compares average emission factors for the full population of field sites in each category, i.e., all visited sites where emissions both were and were not detected. As such, these values account for the average frequency of detection as well as the average magnitude of detected emissions among all sites in each category. In contrast, Figure 9 shows average emissions among only those sites in each category where emissions were detected. The difference in these is analogous to the difference between population and "leaker" emissions factors in the EPA's Greenhouse Gas Reporting Program. On both charts, error bars reflect the propagation of uncertainty estimates associated with the emission measurements taken in this study, where the largest ranges of uncertainty are generally associated with downwind measurements of the largest emissions (see Appendix A).

These results are consistent with findings reported by others. For the Appalachian Basin, this study found average emission rates for sites producing less than 2 BOE/d to be 0.18 kg/h (1.7 TPY, 11 scfh) for small gas sites, 0.038 kg/h (0.37 TPY, 2.4 scfh) for small oil sites, and 0.075 kg/h (0.72 TPY, 4.8 scfh) overall for combined oil and gas sites. For comparison, Deighton et al. (2020) reported average methane emissions of 0.128 kg/h (1.24 TPY; 8.16 scfh) from 48 marginal and gas wells in Ohio, all producing less than 1 BOE/d, and Riddick et al (2019) report average methane emissions of 0.138 kg/h (1.33 TPY; 8.80 scfh) from 74 active conventional oil and gas wells in West Virginia.

5.2.3 Considerations Regarding Liquids Unloading

It is important to note that the results of this study correspond only to emissions observed at the time of each site visit and do not include episodic high emission events, such as liquids unloading or manual liquids removal. This process involves removing liquids from a gas producing well when a buildup of fluid has prevented the flow of gas at the wellhead. Although no liquids unloading events were observed during the site visits, they were reported by the host operators to occur at 118 of the 589 visited sites with various frequencies, as shown on Table 3.

Table 3. *Operator-Reported Frequency of Liquids Unloading Events at Visited Gas Production Sites.*

Reported Frequency	Approx. # per year	Number of Sites
As needed	unknown	84
Annually	1	8
Twice/year	2	5
Once/4 months	3	1
Quarterly	4	1
Once every few months	5	1
Once/2 months	6	5
Monthly	12	6
Twice/month	24	1
Weekly	52	5
Only during maintenance	<1	1

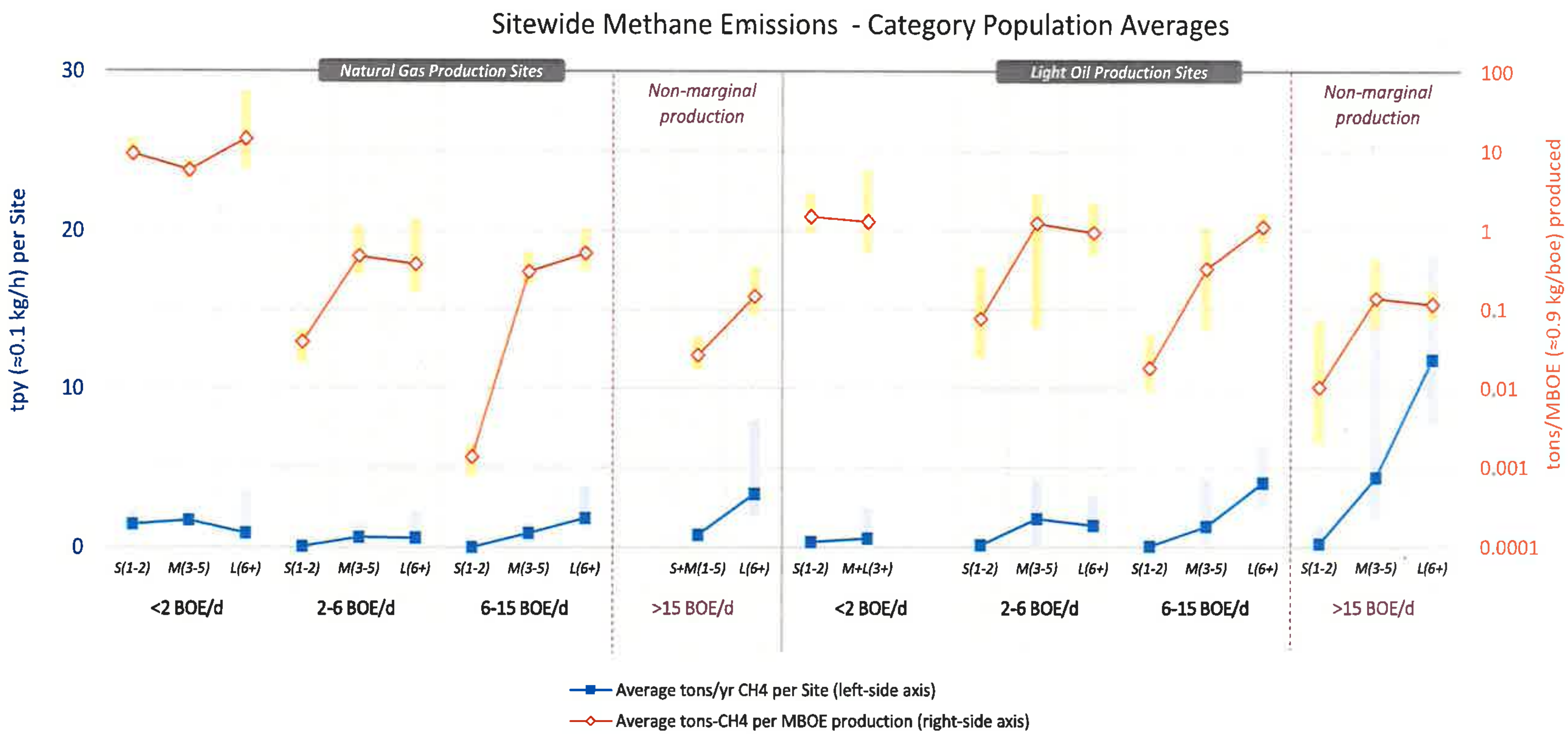


***Figure 8.** Production site category emission profiles – Category Population Averages*

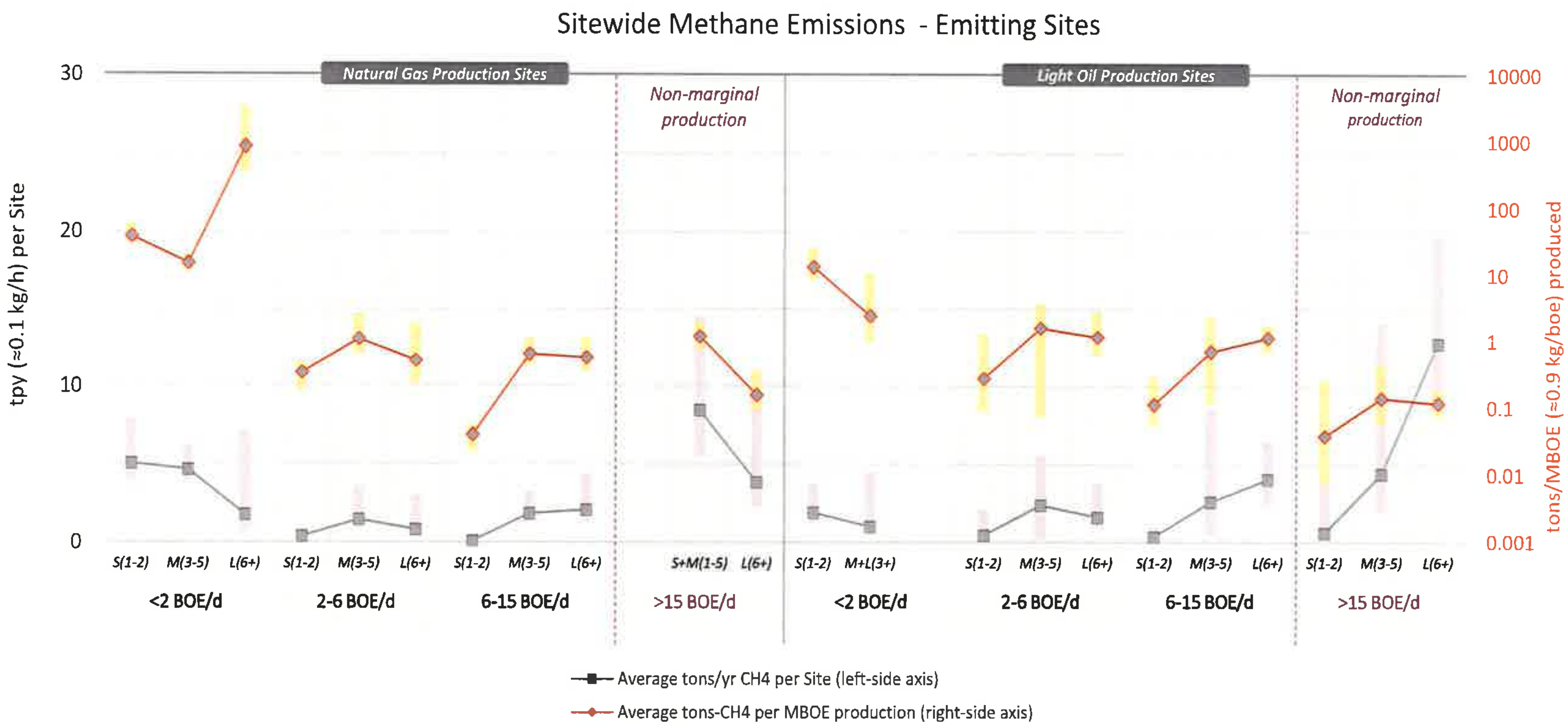


Figure 9. *Production site category emission profiles – Emitting Sites*

Table 4. *Site Category Population Summary*

bin		Production Category	Site Size (Equip. count)	#-sites Visited	#-sites Emission Det.	#-emissions Det.	#-emissions Meas.	Avg. prod rate (boe/d)	Population Average - Site Count-Based (kg/h/site) Avg.	(kg/h/site) *minus*	(kg/h/site) *plus*	(tpy/site) Avg.	(tpy/site) *minus*	(tpy/site) *plus*	Population Average - Production Rate-Based (kg/boe) Avg.	(kg/boe) *minus*	(kg/boe) *plus*	(ton/MBOE) Avg.	(ton/MBOE) *minus*	(ton/MBOE) *plus*
1	Natual gas sites	boe_<2	S(1-2)	28	8	8	6	4.2E-1	1.5E-1	*3.3E-2*	*8.4E-2*	1.5E+0	*3.2E-1*	*8.1E-1*	8.5E+0	*1.9E+0*	*4.8E+0*	9.4E+0	*2.1E+0*	*5.2E+0*
2			M(3-5)	107	39	58	51	8.1E-1	1.8E-1	*3.4E-2*	*5.8E-2*	1.7E+0	*3.3E-1*	*5.6E-1*	5.2E+0	*1.0E+0*	*1.7E+0*	5.8E+0	*1.1E+0*	*1.9E+0*
3			L(6+)	10	5	20	18	1.7E-1	9.2E-2	*5.4E-2*	*2.8E-1*	8.9E-1	*5.2E-1*	*2.7E+0*	1.3E+1	*7.7E+0*	*3.9E+1*	1.4E+1	*8.4E+0*	*4.3E+1*
4		boe_2-6	S(1-2)	19	3	3	3	4.4E+0	6.5E-3	*2.9E-3*	*2.9E-3*	6.3E-2	*2.9E-2*	*2.8E-2*	3.6E-2	*1.6E-2*	*1.6E-2*	3.9E-2	*1.8E-2*	*1.8E-2*
5			M(3-5)	40	17	25	22	3.6E+0	6.5E-2	*2.7E-2*	*9.5E-2*	6.3E-1	*2.6E-1*	*9.2E-1*	4.3E-1	*1.8E-1*	*6.3E-1*	4.8E-1	*2.0E-1*	*7.0E-1*
6			L(6+)	18	13	34	30	4.3E+0	6.1E-2	*3.4E-2*	*1.6E-1*	5.9E-1	*3.3E-1*	*1.6E+0*	3.4E-1	*1.9E-1*	*9.2E-1*	3.8E-1	*2.1E-1*	*1.0E+0*
7		boe_6-15	S(1-2)	21	1	1	1	9.0E+0	4.6E-4	*2.1E-4*	*2.0E-4*	4.5E-3	*2.0E-3*	*2.0E-3*	1.2E-3	*5.5E-4*	*5.4E-4*	1.4E-3	*6.1E-4*	*6.0E-4*
8			M(3-5)	21	10	20	20	7.9E+0	9.1E-2	*2.8E-2*	*7.1E-2*	8.8E-1	*2.7E-1*	*6.8E-1*	2.8E-1	*8.6E-2*	*2.1E-1*	3.0E-1	*9.5E-2*	*2.4E-1*
9			L(6+)	32	28	115	106	9.6E+0	1.9E-1	*7.6E-2*	*2.1E-1*	1.8E+0	*7.4E-1*	*2.1E+0*	4.7E-1	*1.9E-1*	*5.3E-1*	5.2E-1	*2.1E-1*	*5.9E-1*
10		boe_>15	M(3-5)	11	1	3	3	8.0E+1	8.0E-2	*2.9E-2*	*5.7E-2*	7.7E-1	*2.8E-1*	*5.5E-1*	2.4E-2	*8.6E-3*	*1.7E-2*	2.6E-2	*9.5E-3*	*1.9E-2*
11			L(6+)	30	26	132	116	6.2E+1	3.5E-1	*1.5E-1*	*4.8E-1*	3.3E+0	*1.4E+0*	*4.6E+0*	1.3E-1	*5.7E-2*	*1.9E-1*	1.5E-1	*6.2E-2*	*2.0E-1*
12	Oil sites	boe_<2	S(1-2)	76	13	13	9	5.9E-1	3.4E-2	*1.3E-2*	*3.4E-2*	3.3E-1	*1.2E-1*	*3.2E-1*	1.4E+0	*5.1E-1*	*1.4E+0*	1.5E+0	*5.6E-1*	*1.5E+0*
13			M(3-5)	13	7	10	3	1.1E+0	5.6E-2	*3.4E-2*	*2.0E-1*	5.4E-1	*3.3E-1*	*1.9E+0*	1.2E+0	*7.1E-1*	*4.1E+0*	1.3E+0	*7.9E-1*	*4.5E+0*
14		boe_2-6	S(1-2)	35	10	11	6	4.5E+0	1.3E-2	*8.8E-3*	*4.9E-2*	1.3E-1	*8.5E-2*	*4.7E-1*	6.9E-2	*4.7E-2*	*2.6E-1*	7.7E-2	*5.2E-2*	*2.9E-1*
15			M(3-5)	8	6	11	2	3.9E+0	1.8E-1	*1.8E-1*	*2.5E-1*	1.8E+0	*1.7E+0*	*2.4E+0*	1.1E+0	*1.1E+0*	*1.5E+0*	1.2E+0	*1.2E+0*	*1.7E+0*
16			L(6+)	14	12	27	18	4.0E+0	1.4E-1	*6.7E-2*	*2.0E-1*	1.4E+0	*6.5E-1*	*1.9E+0*	8.6E-1	*4.1E-1*	*1.2E+0*	9.5E-1	*4.5E-1*	*1.3E+0*
17		boe_6-15	S(1-2)	24	4	4	2	8.7E+0	6.0E-3	*3.1E-3*	*9.9E-3*	5.8E-2	*3.0E-2*	*9.6E-2*	1.6E-2	*8.5E-3*	*2.7E-2*	1.8E-2	*9.4E-3*	*3.0E-2*
18			M(3-5)	8	4	8	2	1.1E+1	1.3E-1	*1.1E-1*	*3.1E-1*	1.3E+0	*1.1E+0*	*3.0E+0*	3.0E-1	*2.5E-1*	*6.9E-1*	3.3E-1	*2.8E-1*	*7.6E-1*
19			L(6+)	9	9	24	19	9.8E+0	4.2E-1	*1.7E-1*	*2.5E-1*	4.0E+0	*1.7E+0*	*2.4E+0*	1.0E+0	*4.2E-1*	*6.1E-1*	1.1E+0	*4.6E-1*	*6.7E-1*
20		boe_>15	S(1-2)	15	5	5	1	5.1E+1	2.0E-2	*1.6E-2*	*1.2E-1*	1.9E-1	*1.6E-1*	*1.1E+0*	9.4E-3	*7.6E-3*	*5.5E-2*	1.0E-2	*8.3E-3*	*6.1E-2*
21			M(3-5)	1	1	4	4	8.6E+1	4.5E-1	*2.7E-1*	*1.0E+0*	4.4E+0	*2.6E+0*	*9.7E+0*	1.3E-1	*7.4E-2*	*2.8E-1*	1.4E-1	*8.1E-2*	*3.1E-1*
22			L(6+)	14	13	45	36	2.8E+2	1.2E+0	*4.3E-1*	*6.8E-1*	1.2E+1	*4.2E+0*	*6.6E+0*	1.1E-1	*3.7E-2*	*5.9E-2*	1.2E-1	*4.1E-2*	*6.5E-2*

5.3 Equipment-Specific Emissions

As discussed in Section 4.1.2, during the field campaigns, separators, wellheads, and tanks were by far the most common equipment encountered for all types of sites and exhibited the largest volumes of emissions. Meters were commonly encountered at natural gas sites with a much lower emission frequency, and a small number of compressors was also encountered, with a majority of those exhibiting one or more discrete emissions. Table 5 summarizes the types and numbers of all major equipment encountered at the visited sites, the frequency of detected emissions and the average magnitude of emissions among i) emitting equipment only, representing effective "leaker" emissions in the parlance of the EPA Greenhouse Gas Reporting Program, and ii) the full population of observed equipment representing effective population emission factors. These results are presented separately for oil vs. natural gas sites and for the study as a whole vs. regionally for Eastern and Western US, consistent with such breakdowns in the GHGRP, as well as for this study as a whole.

While not every type of equipment where emissions were ultimately detected (such as combustors and glycol heaters) were specifically tallied at every site, Table 5 summarizes the observed emissions at the most commonly seen equipment types and the equipment types identified as the largest or more common sources of emissions. Note, the high frequency of emissions for certain equipment (e.g., >100% among 3-phase separators) reflects the rather frequent observation of multiple emissions on a single unit of equipment and does not mean that emissions were detected from every observed unit. There were occasions where distinct emissions were observed among separate components on the same separator. Nine emissions were attributed to yard piping rather than a specific piece of equipment. These ranged from 0.22 scfh (0.0035 kg/h, 0.033 TPY) to 19 scfh (0.30 kg/h, 2.9 TPY) from small threaded connectors and regulators and were 16 scfh (0.25 kg/h, 2.4 TPY) and 89 scfh (1.4 kg/h, 13 TPY) from an underground line and a pipe manifold building, respectively. Equipment-specific exploratory analyses are described in detail in Appendix B and summarized as follows.

- ***Separator emissions:*** Emission detection frequency is strongly associated with the number of phases (2 or 3) of the separator and site production rates, corresponding to throughput. Maximum and operational design pressures exhibited a strong to moderate association with emission detection frequencies but not magnitude.
- ***Wellhead emissions:*** Only weak associations were apparent between emission detection frequency and evaluated wellhead characteristics. The strongest of these were with host operator, basin, well depth (possibly a proxy for wellhead casing pressure), and gas production rate. Notably, well type and age did not exhibit significant association with either emission frequency or magnitude.
- ***Tank emissions:*** Only weak associations were found between emission detection frequency and evaluated tank characteristics. The strongest of these were with the presence of pressurized or atmospheric vents, oil production rate, and liquid level.

Table 5. Frequency and Magnitude of Equipment Specific Emissions

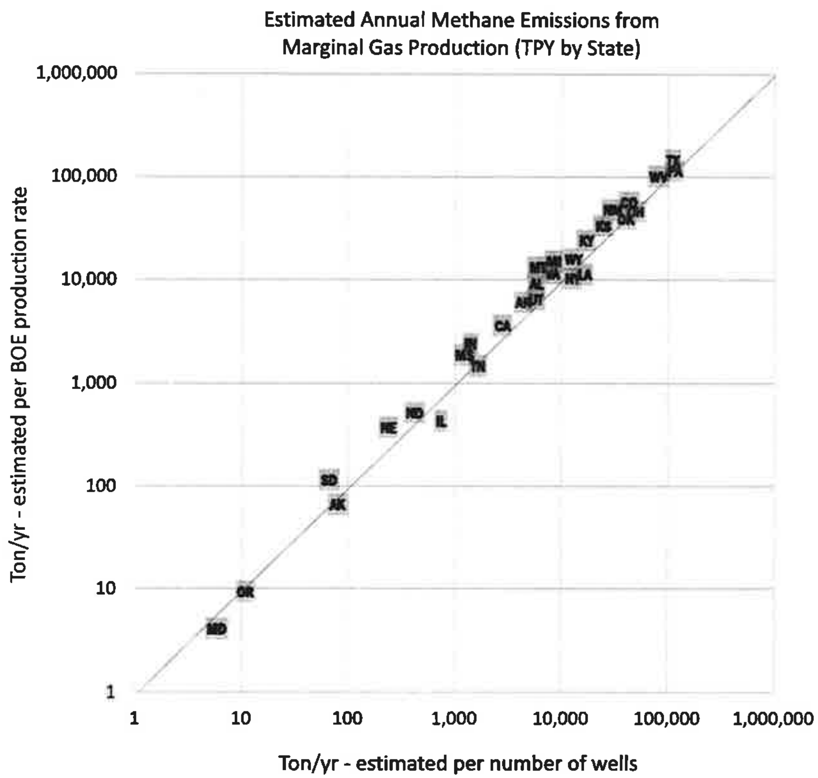
Region / Equipment	Equipment Observed	Emissions Detected	Detection frequency	Emissions Quantified	Avg. Methane Emission Rate						Equipment Observed	Emissions Detected	Detection frequency	Emissions Quantified	Avg. Methane Emission Rate					
					Emitting Equipment			Population Avg.							Emitting Equipment			Population Avg.		
	(#)	(#)	(%)	(#)	(scfh)	(kg/h)	(tpy)	(scfh)	(kg/h)	(tpy)	(#)	(#)	(%)	(#)	(scfh)	(kg/h)	(tpy)	(scfh)	(kg/h)	(tpy)
Eastern US	Natural Gas Sites										Light Oil Sites									
Compressor	4	1	25%	1	14	0.21	2.1	3.4	0.054	0.52	2	0	0%	0	--	--	--	--	--	--
Dehydrator	2	0	0%	0	--	--	--	--	--	--	0	0	--	0	--	--	--	--	--	--
Meter	167	4	2%	3	1.7	0.026	0.25	0.040	0.00063	0.0061	14	2	14%	2	0.52	0.0081	0.078	0.074	0.0012	0.011
Separator	127	14	11%	12	1.6	0.025	0.24	0.17	0.0027	0.026	35	4	11%	1	19	0.30	2.9	2.2	0.035	0.33
2-phase	125	13	10%	11	0.99	0.016	0.15	0.10	0.0016	0.016	20	1	5%	0	--	--	--	--	--	--
3-phase	0	0	--	0	--	--	--	--	--	--	15	3	20%	1	19	0.30	2.9	3.9	0.061	0.59
Tank	155	17	11%	15	14	0.22	2.2	1.6	0.025	0.24	82	25	30%	16	3.3	0.051	0.50	1.0	0.016	0.15
thief hatch	149	3	2%	3	34	0.54	5.2	0.69	0.011	0.10	84	9	11%	7	3.5	0.055	0.53	0.37	0.0059	0.057
vent	176	14	8%	12	9.3	0.15	1.4	0.74	0.012	0.11	29	16	55%	9	3.1	0.049	0.47	1.7	0.027	0.26
Wellhead	159	31	19%	27	11	0.17	1.7	2.1	0.034	0.32	95	15	16%	8	17	0.27	2.6	2.8	0.043	0.42
Yard piping	--	3	--	3	8.0	0.13	1.2	--	--	--	--	0	--	0	--	--	--	--	--	--
Western US	Natural Gas Sites										Light Oil Sites									
Compressor	18	20	111%	20	15	0.24	2.3	17	0.27	2.6	17	9	53%	8	6.8	0.11	1.0	3.6	0.056	0.54
Dehydrator	10	0	0%	0	--	--	--	--	--	--	0	0	--	0	--	--	--	--	--	--
Flare	6	2	33%	1	19	0.30	2.9	6.4	0.10	0.97	13	2	15%	2	39	0.60	5.8	5.9	0.093	0.90
Meter	185	6	3%	5	1.5	0.024	0.23	0.050	0.00078	0.0075	80	3	4%	1	0.15	0.0024	0.023	0.0058	0.000090	0.00087
Separator	191	198	104%	187	2.3	0.036	0.35	2.4	0.038	0.36	133	40	30%	28	42	0.66	6.4	13	0.20	1.9
2-phase	73	29	40%	25	3.4	0.053	0.51	1.3	0.021	0.20	41	11	27%	9	6.6	0.10	0.99	1.8	0.028	0.27
3-phase	114	169	148%	162	2.2	0.034	0.33	3.2	0.050	0.48	82	27	33%	18	62	0.97	9.4	20	0.32	3.1
Tank	340	71	21%	56	5.5	0.087	0.84	1.2	0.018	0.17	189	55	29%	35	58	0.90	8.7	17	0.26	2.5
thief hatch	222	48	22%	38	3.4	0.053	0.51	0.73	0.011	0.11	159	33	21%	23	47	0.73	7.1	9.7	0.15	1.5
vent	103	6	6%	5	0.92	0.014	0.14	0.053	0.00084	0.0081	13	13	100%	6	4.7	0.073	0.71	4.7	0.073	0.71
open top	1	1	100%	0	--	--	--	--	--	--	2	2	100%	2	435	6.8	66	435	6.8	66
Emiss. control dev.	15	5	33%	3	23	0.36	3.5	7.6	0.12	1.2	6	1	17%	1	15	0.24	2.3	2.5	0.039	0.38
Wellhead	260	46	18%	41	26	0.41	4.0	4.6	0.073	0.70	118	30	25%	14	2.6	0.041	0.40	0.7	0.010	0.10
Yard piping	--	2	--	2	9.2	0.14	1.4	--	--	--	--	4	--	3	31	0.48	4.7	--	--	--
Study Total	Natural Gas Sites										Light Oil Sites									
Compressor	22	21	95%	21	15	0.24	2.3	15	0.23	2.2	19	9	47%	8	6.8	0.11	1.0	3.2	0.050	0.49
Dehydrator	12	0	0%	0	--	--	--	--	--	--	0	0	0%	0	--	--	--	--	--	--
Flare	6	2	33%	1	19	0.30	2.9	6.4	0.10	0.97	13	2	15%	2	39	0.60	5.8	5.9	0.093	0.90
Meter	352	10	3%	8	1.6	0.025	0.24	0.045	0.00071	0.0068	94	5	5%	3	0.40	0.0062	0.060	0.021	0.00033	0.0032
Separator	318	212	67%	199	2.3	0.036	0.34	1.5	0.024	0.23	168	44	26%	29	42	0.65	6.3	11	0.17	1.7
2-phase	198	42	21%	36	2.6	0.041	0.40	0.56	0.0088	0.085	61	12	20%	9	6.6	0.10	0.99	1.3	0.020	0.20
3-phase	114	169	148%	162	2.2	0.034	0.33	3.2	0.050	0.48	97	30	31%	19	60	0.94	9.0	18	0.29	2.8
Tank	495	88	18%	71	7.4	0.12	1.1	1.3	0.021	0.20	271	80	30%	51	41	0.64	6.2	12	0.19	1.8
thief hatch	371	51	14%	41	5.6	0.089	0.86	0.78	0.012	0.12	243	42	17%	30	37	0.58	5.6	6.3	0.099	0.96
vent	279	20	7%	17	6.8	0.11	1.0	0.49	0.0077	0.074	42	29	69%	15	3.7	0.059	0.57	2.6	0.040	0.39
open top	1	1	100%	0	--	--	--	--	--	--	2	2	100%	2	--	--	--	--	--	--
Emiss. control dev.	15	5	33%	3	23	0.36	3.5	7.6	0.12	1.2	6	1	17%	1	15	0.24	2.3	2.5	0.039	0.38
Wellhead	419	77	18%	68	20	0.32	3.1	3.7	0.058	0.56	213	45	21%	22	8.0	0.13	1.2	1.7	0.027	0.26
Yard piping	--	5	--	5	8.5	0.13	1.3	--	--	--	--	4	--	3	31	0.48	4.7	--	--	--

5.4 Relative Magnitude and Extent of O&G Production-Related Methane Emissions

Figures 10a and 10b summarize the results of Monte Carlo simulations used to estimate state-specific annual methane emissions estimates marginal vs. nonmarginal oil and gas production operations. As described in Section 4.3, these account for observed and reported regional differences in production types and rates, site characteristics including size (i.e., major equipment counts), equipment types, frequency and magnitude of emissions and related uncertainties. Sensitivity analyses found that assuming the distribution of detected but unmeasured emissions was very highly skewed versus moderately skewed would increase all of these estimates by approximately 1%. On each plot in Figures 10a and 10b, the x-axis represents total estimated methane emissions, in TPY, based on the reported number of wells in each state, and the y-axis represents corresponding estimates, based on the reported oil and gas production in each state. The 95% confidence interval of each result is less than 2% for marginal production and less than 3% for nonmarginal production.

As shown by the distribution of points around each 1:1 diagonal, estimates by the separate estimates generally agree, especially for marginal production. However, for nonmarginal oil production the site count-based estimates is notably larger than the production-based estimate for most states. The reason for this is not clear; however, it could at least partially be due to an overestimation of "site" counts, assumed equal to well counts for nonmarginal categories. Greater scatter exhibited in the results for nonmarginal production is likely due to multiple factors. Figure 8 and Table 4 show that applicable emission factors for the five nonmarginal site categories exhibit much greater ranges of measurement uncertainty than the to 17 marginal site categories. Additionally, nonmarginal production represented only a small proportion (~10%) of sites visited in the regional field campaigns, consistent with the focus and design of this study; however, these exhibited a much larger range of production rates and major equipment counts than marginal production sites and a disproportionate number (~30%) of detected but unmeasured emissions, resulting in even greater uncertainty.

Figures 11 and 12, provide additional perspectives on these results for comparison. As it is impossible to know for a given state whether the site count-based or production-based estimate is more accurate or reliable, the average of these considered the most reasonable estimates, as represented in the bar charts and largest pie charts. Overall, the comprehensive results of this study suggest that i) marginal oil and gas production in the United States may account for approximately 1 million (±140,000) TPY of "every day" methane emissions, as were observed in the regional field campaigns, ii) marginal gas production accounts for an estimated 60% (±10%) of emissions from U.S. natural gas production, and iii) marginal oil production accounts for an estimated 40% (±10%) of emissions from U.S. oil production. Table 6 presents additional details of these findings.



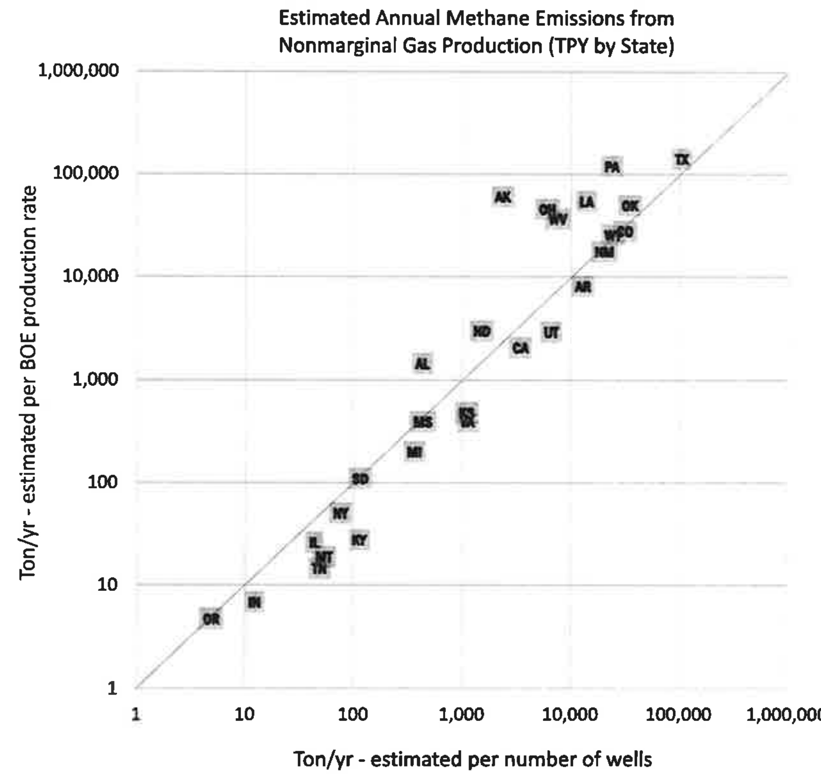


Figure 10(a). *Estimated annual methane emissions by state: Marginal and nonmarginal gas production.*

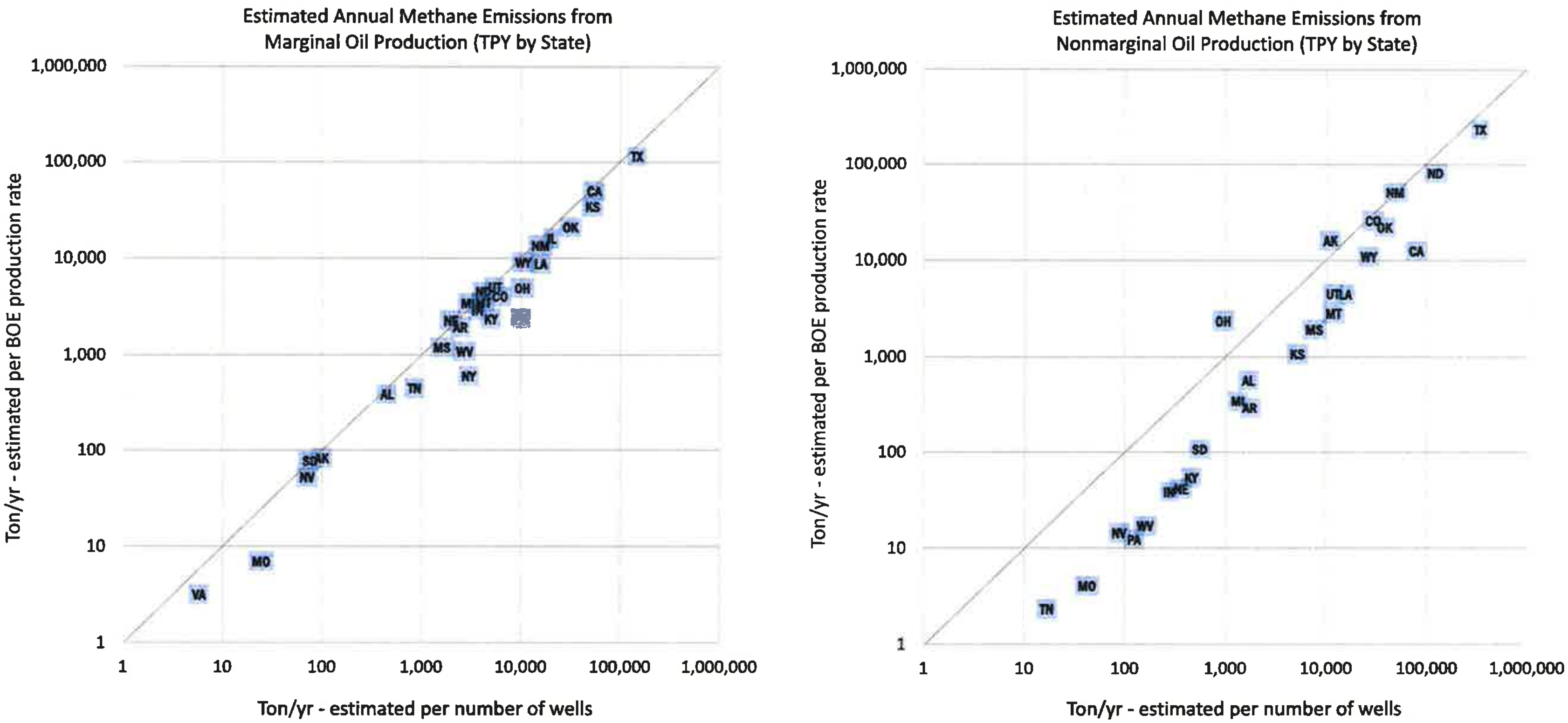


Figure 10(b). *Estimated annual methane emissions by state: Marginal and nonmarginal oil production.*

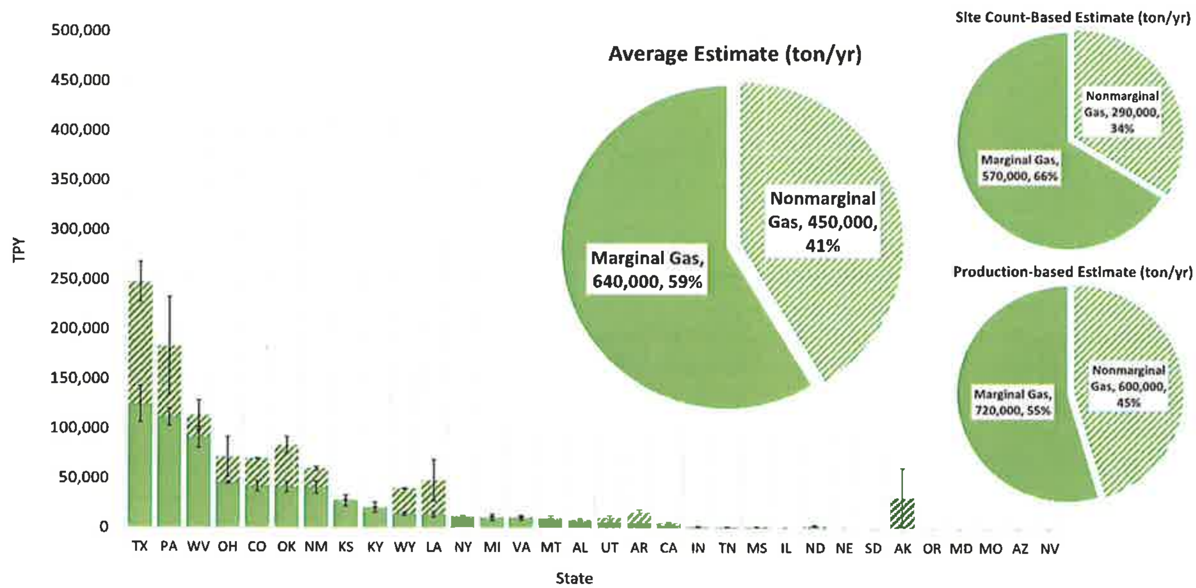


Figure 11. *Estimated overall methane emissions from marginal and nonmarginal gas production.*

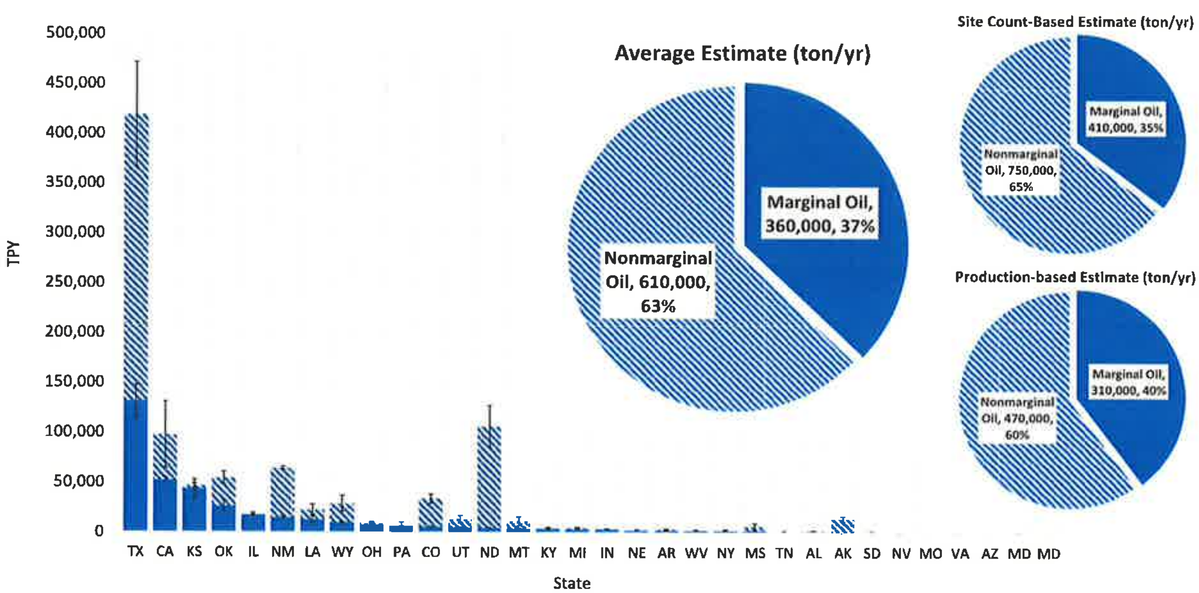


Figure 12. *Estimated overall methane emissions from marginal and nonmarginal oil production.*

Table 6. *Relative Estimated Methane Emissions from Marginal and Nonmarginal O&G Production*

	Approx. Well Count		Annual Production		Estimated Cumulative Methane Emissions			Avg. Pop. Emission Factors	
	count	share	boe/yr	share	ton/yr	Tg/yr	share	tons/yr/well	ton/MBOE
Natural Gas Production									
Marginal	420,000	78%	4.6E+8	7%	640,000 ±80,000	0.58 ±0.08	59% ±12%	1.5 ±0.2	1.4 ±0.2
Nonmarginal	120,000	22%	5.8E+9	93%	450,000 ±170,000	0.41 ±0.16	41% ±12%	3.7 ±1.4	0.077 ±0.030
total gas	*540,000*	*100%*	*6.2E+9*	*100%*	*1,090,000 ±260,000*	*0.99 ±0.23*	*100%*	*2.0 ±0.5*	*0.18 ±0.04*
Oil Production									
Marginal	363,000	80%	3.2E+8	8%	360,000 ±50,000	0.33 ±0.05	37% ±9%	1.0 ±0.1	1.1 ±0.2
Nonmarginal	88,000	20%	3.9E+9	92%	610,000 ±150,000	0.55 ±0.14	63% ±9%	7.0 ±1.7	0.16 ±0.04
total oil	*451,000*	*100%*	*4.2E+9*	*100%*	*970,000 ±210,000*	*0.88 ±0.19*	*100%*	*2.2 ±0.5*	*0.23 ±0.05*
Combined Oil & Gas Production									
Marginal	783,000	79%	7.7E+8	7%	1,000,000 ±140,000	0.91 ±0.13	49% ±11%	1.3 ±0.2	1.3 ±0.2
Nonmarginal	208,000	21%	9.6E+9	93%	1,060,000 ±320,000	0.96 ±0.29	51% ±11%	5.1 ±1.6	0.11 ±0.03
total oil & gas	*991,000*	*100%*	*1.0E+10*	*100%*	*2,060,000 ±460,000*	*1.87 ±0.42*	*100%*	*2.1 ±0.5*	*0.20 ±0.04*

Figure 13 summarizes the estimated geographic distribution of overall methane emissions from marginal oil and gas production across the US. This analysis indicates that the Appalachian Basin produces the largest volume of marginal production-related methane emissions from any single geologic basin, with an estimated 290,000 TPY coming from Pennsylvania, West Virginia, and Ohio, New York, Maryland, and Virginia representing 29% of methane emissions from US marginal oil and gas production. Texas, Oklahoma, and New Mexico, which encompass the Permian plus large parts of the Anadarko, San Juan, and other basins, together emit an estimated 380,000 TPY of methane (38%).

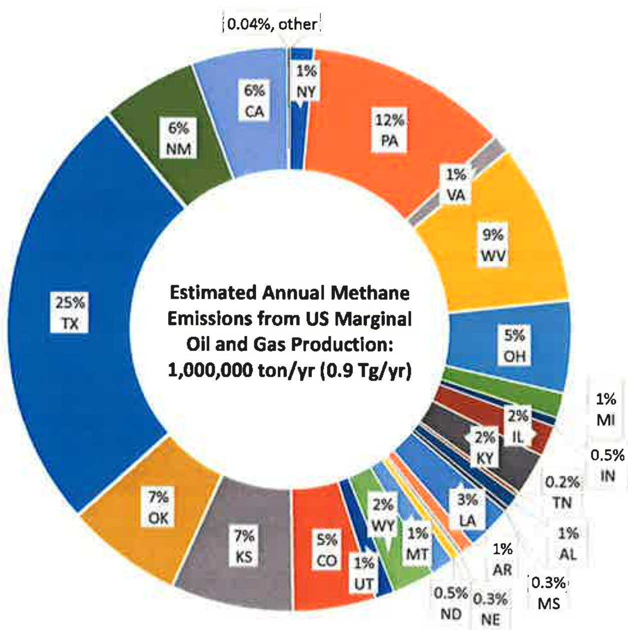


Figure 13. *Estimated regional distribution of methane emissions from US marginal oil and gas production.*

6.0 ACKNOWLEDGMENTS

6.1 Technical Advisory Steering Committee

There has been a high level of interest and participation on this project from industry and regulatory stakeholders concerned with quantification of methane emissions from marginal oil and gas wells. A Technical Advisory Steering Committee (TASC) was established and implemented to provide input and feedback on key aspects of the project work scope. The TASC was tiered, with a full committee that included representation from industry, regulators, non-government organizations, and academia, and a sub-committee comprised of industry representatives only. The industry sub-committee played a major role during the initial data assessment and master workplan development. Subsequently, the full TASC was engaged to ensure site selection, regional workplans, measurement technologies, and data measurement and analysis approaches were adequately addressed to meet stakeholder requirements and QA/QC standards. The TASC convened on four occasions as follows:

- ***April 2019:*** Four calls covering identical topics were held to introduce the project, discuss the preliminary literature review, planning of the operator data survey, and proposed field strategy.
- ***August 2019:*** Four calls covering identical topics were held to discuss the results and findings of the Data Source Status Assessment Report and draft Master Workplan, including site selection criteria and procedures for the subsequent field investigations. The research team incorporated extensive TASC feedback in preparation of the Regional Field Workplans.
- ***March 2020:*** Two calls covering identical topics were held to discuss preliminary results and findings from Field Campaign 1 and plans for Field Campaign 2.
- ***September 2021:*** Two calls covering identical topics were held to discuss preliminary results and findings from Field Campaigns 2 and 3 and plans for comprehensive data analyses.

Recurring engagement and open communication with the TASC provided excellent opportunities for the GSI and CSU project team to inform key stakeholders of project plans and findings and for TASC participants to increase project efficiency by providing timely feedback on sampling protocols, data analysis, interpretation of findings, and review of preliminary draft reports. The researchers gratefully acknowledge the interest and participation all TASC members, with special thanks to participants who engaged actively with the research team through constructive dialog and discussions and provided concrete, unbiased input and feedback.

6.2 Operator Survey Respondents and Facilitators

Effective design and planning of the regional field campaigns and the extrapolation of results for comparison of nationwide marginal and nonmarginal production-related emissions was largely made possible by a wealth of data contributed by respondents to the confidential, data-blinded operator survey conducted at the beginning of this project. The research team gratefully acknowledges all respondents who took time to complete and return the survey questionnaire in addition to multiple cooperating industry organizations throughout the country, who widely disseminated the questionnaire and encouraged their membership and others to support this study.

6.3 Field Site Host Operators and Escorts

Effective planning and execution of the field campaigns and the interpretation of results would not have been possible without access to field sites and supplemental activity data graciously and generously contributed by 15 host operators. These companies cooperated extensively with the research team under binding agreements that ensured protections for the integrity of the project, unbiased selection of field sites, host anonymity outside of the project team, and data blinding of company confidential and proprietary information, including all identifying information on specific field sites. The researchers gratefully acknowledge the assistance of dozens of individuals with these companies, from corporate executive, administrative, and EH&S personnel to regional field superintendents, local well pumpers and supervisors, whose knowledge, experience, insights, advice, and tremendous cooperation with the project team were invaluable.

6.4 Project Funders

The project was primarily funded under an assistance agreement with U.S. Department of Energy, Office of Fossil Energy, and managed by the National Energy Technology Laboratory (NETL). Supplemental funding was provided by the American Petroleum Institute (API), the Michigan Oil and Gas Association, the Indiana Oil & Gas Association, the Illinois Oil & Gas Association, the Kansas Independent Oil and Gas Association, the University of Texas System-University Lands, and other private contributors.

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APPENDIX A

Field Measurement Data Reduction

APPENDIX A
Field Measurement Data Reduction

Field measurements to quantify methane and/or VOC emissions at marginal well sites were made using both onsite, direct, and downwind measurements. Sources identified onsite during Optical Gas Imaging (OGI) surveys were measured directly using a Bacharach Hi-Flow Sampler (Hi-Flow) that was specially modified to enable canister samples to be drawn from the inlet flow stream. Canister samples were drawn for a subset of Hi-Flow measurements and were analyzed for gas species composition by a third-party lab using ASTM D-1945 compliant methods. Canister samples were taken for 249 of 460 Hi-Flow measurements to provide insight into typical gas compositions and provide a means for correcting Hi-Flow sensor response variation due to gas composition changes from calibration gas. Multiple samples were not drawn for measurements with a common (or similar) source or if the gas composition did not change at the facility. Instead, the first sample drawn was considered representative. For example, multiple emissions on a common gas feed would use the same gas composition sample for correction. Multiple samples were taken when the gas composition was expected to differ significantly. For example, an emission on a wellhead and a tank would require two samples.

Figure A1: *Direct, onsite measurements were performed with a Bacharach Hi-Flow sampler that was specially modified to allow canister samples to be drawn from its inlet.*

Downwind measurements were made using OTM33A or dual tracer flux methods with the CSU mobile laboratory. The mobile laboratory was equipped with a 3-D sonic anemometer, GPS, laser range finder, Aerodyne Research Inc QC-TLDS, Picarro G-2210i, and Licor 850 trace gas analyzers.

Figure A2: *The CSU mobile laboratory was used to make downwind measurements using both OTM33A and dual tracer flux methods. The lab is equipped with trace-gas analyzers targeting methane, nitrous oxide, acetylene, carbon dioxide, and water vapor, and supporting instrumentation to collect weather and positioning data.*

Onsite, Direct Measurements

Field measurements were made using a Bacharach Hi-Flow Sampler (Hi-Flow) which was specially modified for canister sampling. The Hi-Flow is currently the only known (commercially available) instrument for making total capture, direct emission rate quantifications of identified emission sources. The device draws in the total emission being sampled entrained in high volume of air and measures the total flow and the gas concentration. An emission rate is calculated from these measurements. The device is typically calibrated on methane at both low (2.5% CH4 by volume) and high (99.99% CH4 by volume) concentrations. The Hi-Flow does not measure methane directly; it measures whole gas response relative to the calibration gas and is sensitive to other hydrocarbon species. Therefore, corrections needed to be made to individual measurements based on the specific gas composition encountered during that measurement. Hi-Flow measurement parameters were recorded for each measurement including nominal flow setpoint (25%, 50%, 75%, or 100%), "Flow LPM", "Leak %" and "Leak LPM". The gas sensor within the Hi-Flow operates in one of two modes: catalytic oxidation (CatOx) or thermal conductivity (TCD). The transition between these two modes happens when the Leak % reaches 5% (nominally) but can vary slightly based on calibration and sensor condition.

The subset of measurements where lab samples were taken directly were compared to the Leak % reported by the Hi-Flow during measurement, as shown in Figure A3. The was done by computing a "Lab Canister Leak %" by partitioning the lab results into "whole gas" and "air" and calculating the whole gas percent of the mixture. "Air" was made of nitrogen, oxygen, and a proportional amount of carbon dioxide based on a 400-ppm atmospheric mixing ratio. The remaining carbon dioxide and hydrocarbon species were considered "whole gas" from the emission source and used to calculate a "Lab Canister Leak %."

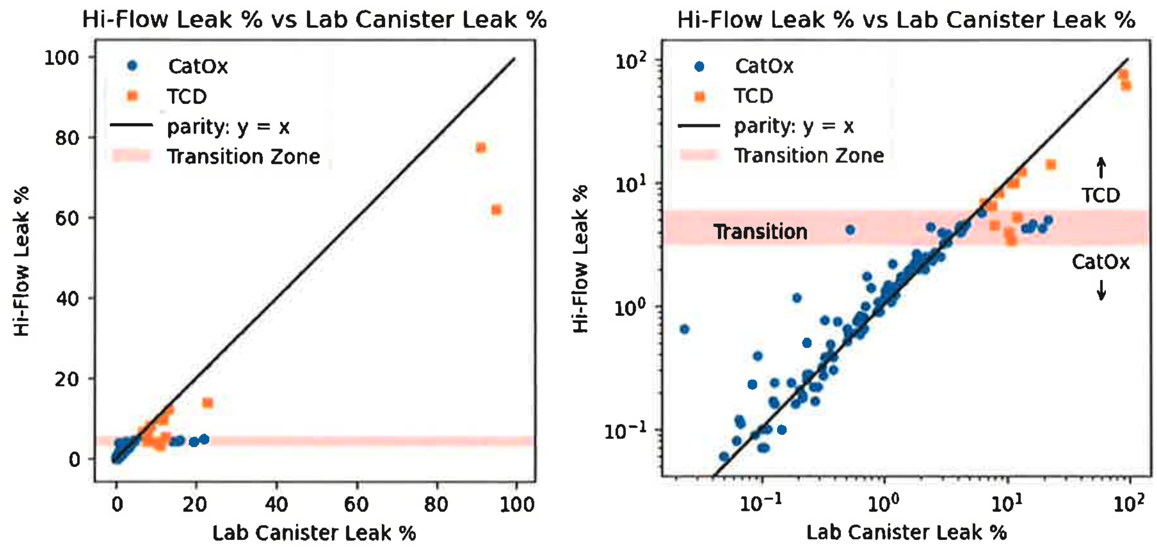

Figure A3: *Hi-Flow indicated leak % vs calculated lab canister leak % results. Linear scale plot on left, log-log scale plot on right. The high flow overpredicted leak % relative to lab results for lower concentrations (CatOx mode) and under predicted leak % relative to lab results at higher concentrations (TCD mode). No clear relation was evident in the transition zone between the two modes.*

Results shown in Figure A3 indicate that Hi-Flow and canister results follow similar trends but disagree at both low and high concentrations. This comparison also illustrates that no clear relationship can be established in the "transition zone", defined here as Hi-Flow indicated "Leak %" between 3 % and 6 %. As a first step in understanding this apparent discrepancy, gas speciation from lab canister analyses were used to compute expected relative responses of the instrument in both CatOx and TCD modes based on sensor response characteristics reported in data sheets. These did not improve agreement between Lab Canister Leak % and Hi-Flow Leak % substantially, and only changed Hi-Flow Leak % values slightly. This suggests that some other factor (or, more likely, combination of factors) influence the Leak % results reported by the Hi-Flow. Transition mode points were not considered during these comparisons.

Next, Hi-Flow Leak % and Lab Canister Leak % were compared considering the inaccuracies in each measurement method. The Hi-Flow manual states that the overall reported leak rate uncertainty is +/- 10 % of the reported value, the flow measurement is +/- 5 % of the reported value and the gas concentration measurement is the greater of 0.02 % or 5 % of the measured value. Tests in our own laboratory indicate that the flow measurements were +/- 5-6 % of the reported value using a calibrated laminar flow element. The uncertainty for Lab Canister Leak % uncertainty was calculated by propagating repeatability limits indicated for each species measurement in each sample through the calculation used to derive the Lab Canister Leak %. For the sake of comparison both Hi-Flow and lab were considered a 95% (1.96 sigma) uncertainty. The results were compared using a variance-weighted, least-squares (VWLS) regression for each mode, as shown in Figure A4. This comparison considers the uncertainty in each method, for each data point. Further, a bootstrap of the VWLS fit was performed by randomly varying the values of each point in accordance with its individual uncertainty and then re-performing the VWLS fit 1000 times. This provides a confidence interval on the fit and indicates the likelihood of bias at a given confidence level.

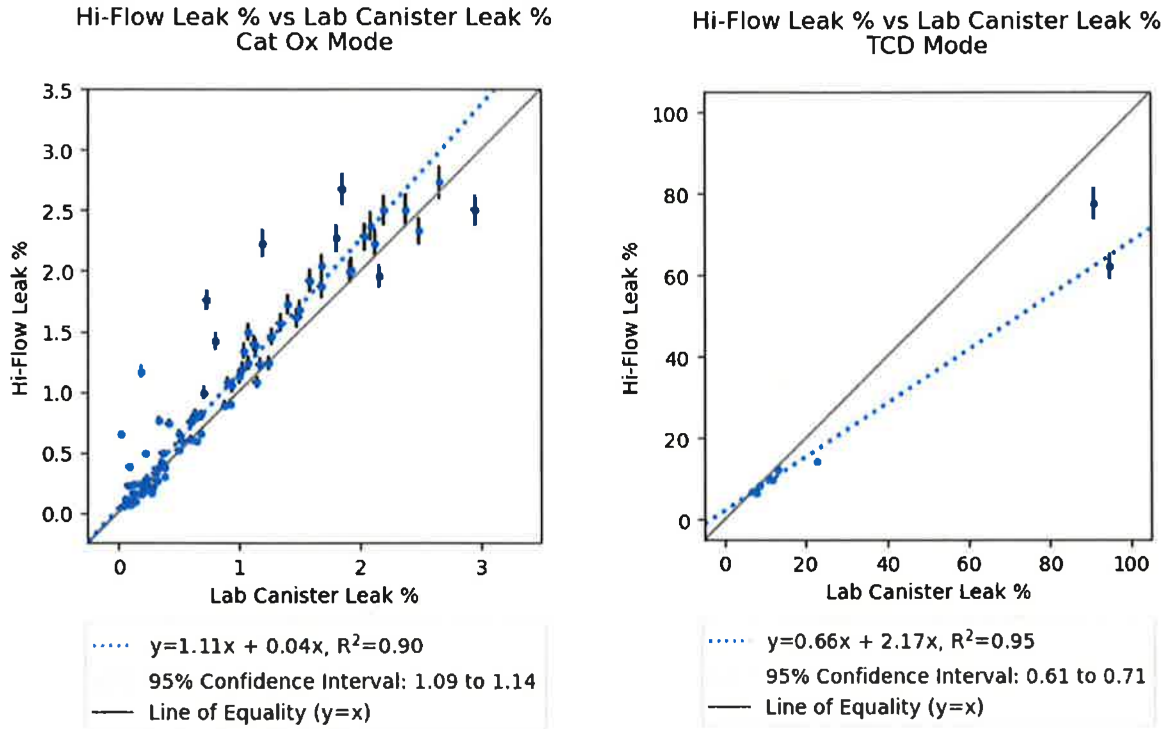

Figure A4: *VWLS regressions for Hi-Flow Leak % vs Lab Canister Leak % in both CatOx (left) and TCD (right) modes. Results indicate a bias in each of the modes. In CatOx mode, Hi-Flow Leak % is 11% high, in aggregate, relative Lab Canister Leak % results. In TCD mode, Hi-Flow Leak % is 44% low, in aggregate, relative Lab Canister Leak % results.*

For CatOx mode, the VWLS comparison indicated that Hi-Flow Leak % reported values were biased 11% high relative to Lab Canister Leak % results. The parity line was not included in the 95% confidence interval range of the bootstrap fits, indicating that the results are likely biased. An analogous procedure was performed for TCD mode measurements which indicate that Hi-Flow TCD measurements were biased 44% low relative to lab results. The confidence interval on the VWLS fit also did not include the parity line indicating that the results are biased 44% low at the 95% confidence level.

To correct for errors introduced by sampling gas composition differing from calibration, and establish an uncertainty estimate for each individual measurement (specific to the dataset acquired in this study), the following approach was used. First, to account for the bias relative to the Lab Canister Leak % results, all CatOx and TCD Leak % measurements were transformed using the VWLS best-fit equation to bring them into parity with Lab Canister Leak % results. Next, an empirical uncertainty was derived for each Hi-Flow measurement emission rate in a Monte Carlo model which considered the residuals from the VWLS fit (specific for each mode), the sensor uncertainty, and the flow uncertainty. For each measurement 10,000 Monte Carlo iterations were performed to provide a range of possible results for each measurement and provide a central, lower, and upper estimate. In each iteration of the model, Hi-Flow measurements falling in the transition zone were discarded and then randomly assigned a value from Lab Canister Leak % observations within the transition zone.

Most Hi-Flow measurements of a single emission source were replicated twice, each at a different Flow LPM. However, some measurements had only one replicate and some had several. For some emission points, several individual Hi-Flow measurements needed to be summed to quantify the emission entirely. Bias-corrected individual measurements (with uncertainty from the Monte Carlo model) were combined (replicates averaged and/or summed) using appropriate logic and quadrature rules for the individual case to result in a final emission rate with uncertainty.

Downwind Measurements

Downwind measurements were made using both OTM33A and dual tracer flux methods. OTM33A was used for all but one downwind measurement, which employed dual tracer flux. Tracer flux application was limited by the availability of downwind roads transecting plumes, and often the presence of closely grouped, confounding sources. Additionally, OTM33A measurements can be performed in a shorter time (20 minutes to 1 hour) compared to dual tracer flux (2-3 hours) which aligned well with the goal of maximizing the number of facilities screened each day. OTM33A measurements were offsite, onsite, or on site-access roads not suitable for transecting emission plumes from the facility. The fact that OTM33A measurements are made while the vehicle is stationary makes measurements from adjacent open terrain possible, where transects would not be feasible. Most OTM33A measurements made were of a single sources or closely spaced group of sources which had previously been identified during an OGI survey and could be isolated from other sources and quantified directly. Both measurement techniques proved useful when the presence of hydrogen sulfide (H_2S) gas eliminated the possibility of direct measurement.

Forty-one OTM33A measurements were made, with emission rates ranging from 0.02 to 368 SLPM. Downwind measurement distances were most typically between 30 m and 60 m but ranged between 12 and 250 m. Distances were measured with a laser rangefinder (Nikon ProStaff 3i) at the time of measurements and confirmed using satellite imagery (Google Earth) during data processing. Measurement periods were typically 20 minutes in length. Time-aligned ethane concentration data (Aerodyne QC or Picarro G-2210i) TLDAS instantaneous (1 Hz) wind speed and direction (Gill Windmaster or Gill Windsonic) were combined using software based on the EPA OTM33A method as published[1]. Wind bin sizes were varied between 6 and 30 degrees for each measurement to account for variation in wind speed, direction, and downwind distance in varying atmospheric stability classes. This effort was performed manually to minimize residuals to Gaussian fits and ensure that binned data points followed a Gaussian profile, as shown in Figure A5. Each OTM33A measurement was assigned an uncertainty of (+/- 30 %) of the measured value based on tests of the method against known releases in previous work [2–4].

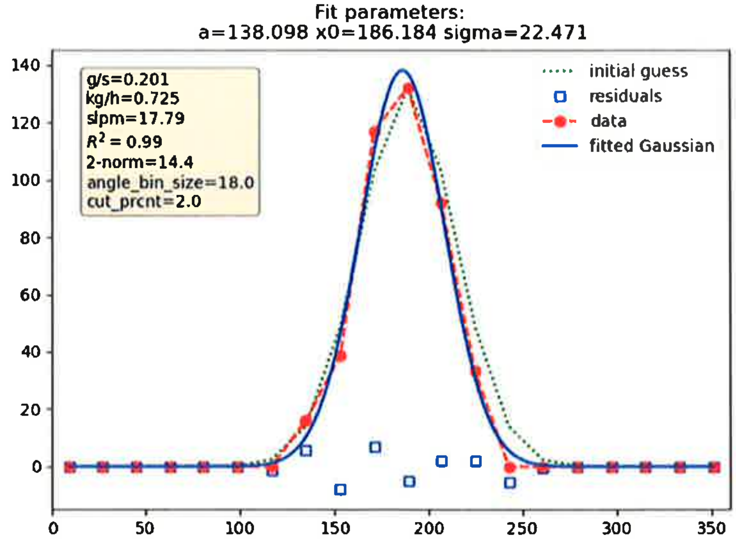

Figure A5: *Example OTM33A measurement computation output.*
Wind bin sizes were varied to identify a best fit.

One dual tracer flux measurement was made during the field campaign. This measurement was of a tank battery with high H_2S content. The measurement was ideally sited with unimpeded downwind access and an absence of upwind or nearby confounding sources. Ten dual correlation plumes were accepted after passing QA/QC criteria outlined in Roscioli et al.[5] Measurement uncertainty for this source is reported as a 95% confidence interval about the mean based on a bootstrap mean performed on the emission rate calculated for each of the ten individual plumes.

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5. Roscioli, J. R.; Yacovitch, T. I.; Floerchinger, C.; Mitchell, A. L.; Tkacik, D. S.; Subramanian, R.; Martinez, D. M.; Vaughn, T. L.; Williams, L.; Zimmerle, D.; Robinson, A. L.; Herndon, S. C.; Marchese, A. J. Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Methods. Atmos Meas Tech 2015, 8 (5), 2017–2035. https://doi.org/10.5194/amt-8-2017-2015.

APPENDIX B

Statistical Exploratory Data Analyses

APPENDIX B
Statistical Exploratory Data Analyses

Exploratory data analyses were performed identify and assess the significance of possible correlations among:

i) Key metadata associated with various site, equipment, and operational conditions documented in the study field campaigns, such as well/site age, production rate, main product type, equipment count, region, and operator).

ii) The frequency of detected emissions among visited sites and observed equipment.

iii) The magnitude of qualified methane and/or whole gas emissions measurements.

All data variables were evaluated as either numeric values or categorical variables. A Spearman's Rank Correlation was used to assess correlations between numeric variables, and a Chi-Squared Test or a Fisher Test (depending on the sample size of the compared dataset) was used to assess the independence of categorical variables. In each case, a p-value 1% was used to reject the null hypothesis that any two compared variables are independent. In other words, any test with a p-value less than or equal to 1% indicates the compared variables are not independent.

Factors specific to major equipment types or components were investigated to identify any significant correlation to emission detection frequency or measured methane or whole gas emission rates. Emission rates were observed and compared based on their causes, identifying where the emitting components warranted repair or if operational conditions or practices warranting improvement.

CORRELATION ANALYSIS METHODS

Categorical Variables

Depending on sample size, a Chi-Squared Test or a Fisher was used to assess correlations between key categorical variables and i) the frequency of detected emissions and ii) the magnitude of measured emissions. Where possible, a Chi-Squared Test was used to determine if two categorical variables were independent; however, if the sample size was too small (expected frequency less than 5%) a Fisher Test was used. For purposes of these analysis, emissions frequency and magnitude (as numerical variables) were converted to categorical variables as follows:

- Low - value <= 25th Percentile
- Medium - value > 25th Percentile and value < 75th Percentile
- High - value >= 75th Percentile

Categorical variables were similarly established for sitewide equipment counts (a proxy for "site size") and sitewide (total) oil and gas production rates using the following bins based on the observed numeric distributions of these variables:

- Small = 1 piece of equipment
- Medium = 2-3 pieces of equipment

- Large = 4-5 pieces of equipment
- X-Large = 5+ pieces of equipment
- boe_0 = 0 boe/day
- boe_0-1 = 0-1 boe/day
- boe_2-4 = 2-4 boe/day
- boe_4-8 = 4-8 boe/day
- boe_8-16 = 8-16 boe/day
- boe_32-64 = 32-64 boe/day
- boe_64-128 = 64-128 boe/day
- boe_>128 = 128+ boe/day

In the tables below, a p-value of less than or equal to 1% for both the Chi-Squared and Fisher tests was used to reject the null hypothesis that the compared variables are independent. Related test statistics are also shown for the Chi-Squared tests, where the primary test statistic is reflective of the sample size, and the adjusted statistic (contingency coefficient) is normalized to range from 0 to 1 independent of sample size. These adjusted test statistics can be used as a relative indicator of the strength of association between compared variables; however, they do not indicate or account for positive vs. negative association. For interpretation, the relative strength of association among variables compared using a Chi-Squared test was considered based on the following scale:

- Weak: Chi-Squared adjusted statistic between 0.0 – 0.39
- Moderate: Chi-Squared adjusted statistic between 0.40 – 0.59
- Strong: Chi-Squared adjusted statistic between 0.6 – 1.0

Numeric Variables

A Spearman's Rank Correlation was used to assess correlations between key numeric variables and specific numeric values quantifying i) the frequency of detected emissions and ii) the magnitude of measured emission for each site or type of evaluated equipment. Spearman's Rank Correlation is a non-parametric method used to test the hypothesis of no association between population datasets and indicates if any significant monotonic relationship (either increasing or decreasing) exists between the compared variables. The Spearman rank order coefficient (rho) falls between -1 (perfectly negative correlation) and +1 (perfectly positive correlation). In the tables below, a p-value of less than or equal to 1% for the Spearman's Rank Correlation indicates the compared variables are associated. For interpretation, the relative strength of association among variables compared using a Spearman's Rank Correlation was considered based on the following scale:

- Weak: Spearman *rho* between +/- 0.0 – 0.39
- Moderate: Spearman *rho* between +/- 0.40 – 0.59
- Strong: Spearman rho between +/- 0.6 – 1.0

SITEWIDE EMISSIONS ANALYSIS

Exploratory analyses of sitewide emissions separately considered the detection of one or more emissions at any type of equipment, the frequency of emissions expressed as the number of detected emissions divided by the total pieces of equipment at a site, and the total magnitude of methane and whole gas emissions at all sites where 100% of detected emissions were successfully quantified.

Variables included in the exploratory analysis of sitewide emissions were:

- Primary product – gas or oil
- Gas production rate, boe/d
- Oil production rate, boe/d
- Total O&G production, boe/d
- Total O&G production (categorical)
- Major equipment count (numeric)
- Major equipment count/Site "size" (categorical, e.g., small, medium, large)
- Gas production frequency
- Oil production frequency
- Routine emissions monitoring frequency
- Host operator
- Basin
- Eastern or Western US
- Age of the well or site

Table B.1 summarizes the site variables on which sitewide emissions frequency and/or magnitude were determined to be dependent. Site emission frequency is most strongly correlated to major equipment count, especially as a categorical variable (described above) and moderately positive with the numeric value. Site equipment count also exhibited the strongest associations among evaluated numerical variables with both frequency and magnitude of emissions, yet with only a moderate positive correlation with detection frequency and weak associations with whole gas and methane emission rates. Weak correlations were also consistently detected among both the frequency and magnitude of emissions, total oil and gas production, and gas production rates.

Weak associations were also noted with either detection frequency or magnitude and host operator or region; however, no such associations were noted consistently with both frequency and magnitude, as were major equipment counts and total oil and gas production. Moreover, any apparent association with host operator could be due to the large range in the number of sites visited with each operator, ranging from 3 (including, 100% of one operator's wells) to over 100 across several of the regions. This was not further evaluated due to the strength of other more likely significant correlations.

Table B.1 *Summary of Site Variables Associated with Sitewide Emissions Detection Frequency and Magnitude*

Variable-Y	Test(s)	Chi/Fisher p-Value	Adjusted Statistic	Spearman p-Value	Spearman *rho*	Est. Association
Frequency of Detected Emissions						
Gas production rate	Spearman	-	-	8.06e-03	0.112	weak
Total O&G production	Fisher, Spearman	1.00e-03	-	1.09e-04	0.163	weak
Basin	Chi-Squared	2.91e-13	0.414	-	-	moderate
Eastern or Western US	Chi-Squared	8.94e-05	0.248	-	-	weak
Emissions monitoring frequency	Fisher	5.00e-04	-	-	-	-
Major equipment count	Chi-Squared, Spearman	1.38e-46	0.648	2.14e-27	0.42600	strong (cat.), moderate (num.)
Whole Gas Emission Rate – Sitewide Average						
Host Operator	Fisher	0.0040	-	-	-	-
Basin	Fisher	0.0030	-	-	-	-
Methane Emission Rate – Sitewide Average						
Host Operator	Fisher	0.0025	-	-	-	-
Basin	Fisher	0.0030	-	-	-	-
Well Age	Spearman	-	-	5.95e-03	0.2930	weak
Whole Gas Emission Rate – Sitewide Total						
Host Operator	Fisher	0.0005	-	-	-	-
Major equipment count	Fisher, Spearman	0.0005	-	8.43e-09	**0.3900**	weak
Gas production rate	Spearman	-	-	3.83e-04	0.2530	weak
Total O&G production	Spearman	-	-	9.85e-03	0.1850	weak
Methane Emission Rate – Sitewide Total						
Host Operator	Fisher	0.01000	-	-	-	-
Eastern or Western US	Chi-Squared	0.00544	0.312	-	-	weak
Major equipment count	Fisher, Spearman	0.00100	-	8.28e-07	0.3370	weak
Gas production rate	Spearman	-	-	1.29e-03	0.2300	weak
Total O&G production	Spearman	-	-	5.54e-04	0.2460	weak

EQUIPMENT EMISSIONS ANALYSIS

Exploratory analyses of equipment-specific emissions focused exclusively on the three most frequently encountered, most frequently emitting, and largest emitting types of equipment: tanks, separators, and wellheads. Factors considered for all three types of equipment type included host operator, site production status (active, inactive, shut-in, etc.), basin/region, primary product, oil and gas production rates, and production frequency. Other factors were specific to the equipment characteristics. Tank emissions were evaluated against the quantity of hatches and vents, whether tank vents were atmospheric or pressurized, the fluid level of the tank while onsite (fullness). Wellhead emissions were evaluated against variables such as the presence of casing vents, well age, well depth (where pressure of the production formation could relate to casing head pressure), artificial lift type, and whether the well was producing brine. Separator emissions were evaluated against variables such as separator age, the number of phases it was designed to separate, maximum design pressure, and operational pressure.

Equipment were first evaluated against all available data to explore factors relating to whether an emission was either detected or not detected at a piece of equipment, then variables associated with the occurrence of detections were further analyzed relative to the frequency of and magnitude of emissions among the respective equipment types, Table B.2 displays the variables which were determined to be dependent based on tests based on equipment type. Key findings of the equipment-specific exploratory analysis are as follows:

- ***Separator emissions:*** Emission detection frequency appears to be strongly associated with the number of phases (2 or 3) of the separator and site production rates, corresponding to throughput. Maximum design pressures exhibited a strong statistical association with emission detections, however operational pressure had a moderate association. Although the adjusted Chi-Squared statistic indicates even stronger correlation the site basin, this is most likely due to the prevalence and near uniqueness of encountering only 3-phase vs. 2-phase separators in some of the basis.
- ***Wellhead emissions:*** Only weak associations were apparent between emission detection frequency and evaluated wellhead characteristics. The strongest of these were with host operator, basin, well depth (potentially a proxy for wellhead casing pressure), and gas production rate.
- ***Tank emissions:*** Only weak associations were found between emission detection frequency and evaluated tank characteristics. The strongest of these were with the presence of pressurized or atmospheric vents, oil production rate, and liquid level.

Table B.2: *Correlations determined through Fisher and Chi-Squared tests for equipment types.*

Variable-Y	Test(s)	P-Value	Adjusted Statistic
Separator Emissions Detection			
Host Operator	Fisher	5.00e-04	-
Basin	Chi-Squared	3.63e-53	0.749
Eastern or Western US	Chi-Squared	5.28e-16	0.434
Monitoring Frequency	Fisher	5.00e-04	-
Active/Inactive	Chi-Squared	9.84e-04	0.216
Primary Product	Chi-Squared	9.02e-13	0.387
Frequency of Oil Production	Chi-Squared	7.49e-04	0.231
Average Oil Production Rate	Chi-Squared	1.04e-13	0.44
Average Gas Production Rate	Chi-Squared	1.05e-13	0.439
Sitewide Production Rate	Chi-Squared	9.36e-12	0.408
Max Pressure	Chi-Squared	1.71e-31	0.677
Operational Pressure	Chi-Squared	2.71e-14	0.504
Equipment Age	Chi-Squared	2.07e-03	0.22
Separator Phases	Chi-Squared	8.97e-15	0.432
Wellhead Emissions Detection			
Host Operator	Fisher	5.00e-04	-
Basin	Chi-Squared	8.39e-05	0.267
Well Age (Years)	Chi-Squared	6.42e-03	0.227
Well Depth (Ft)	Chi-Squared	7.07e-04	0.268
Monitoring Frequency	Fisher	7.00e-03	-
Average Gas Production Rate	Chi-Squared	1.13e-04	0.235
Sitewide Production Rate	Chi-Squared	8.36e-03	0.172

Variable-Y	Test(s)	P-Value	Adjusted Statistic
Tanks Emissions Detection			
Host Operator	Fisher	5.00e-04	-
Basin	Chi-Squared	2.47e-03	0.201
Oil Production Frequency	Chi-Squared	1.10e-03	0.197
Average Oil Production Rate	Chi-Squared	3.95e-07	0.275
Average Gas Production Rate	Chi-Squared	2.23e-03	0.179
Sitewide Production Rate	Chi-Squared	4.10e-04	0.202
Tank Fullness	Chi-Squared	6.32e-04	0.22
Primary Product	Chi-Squared	6.86e-04	0.173
Quantity of Hatches	Fisher	5.00e-04	-
Pressurized or Atmospheric Vents	Chi-Squared	1.52e-09	0.325

Table B.3: *Correlations determined through Fisher, Chi-Squared, and Spearman tests for equipment types.*

Variable	Test(s)	P-Value	Adjusted Statistic	Spearman P-Value	Spearman Rho
Magnitude of Whole Gas Emission Rate - Separators					
Host Operator	Fisher	0.0070	-	-	-
Basin	Fisher	0.0045	-	-	-
Monitoring Frequency	Fisher	0.0010	-	-	-
Magnitude of Methane Emission Rate - Separators					
Host Operator	Fisher	0.0005	-	-	-
Basin	Fisher	0.0015	-	-	-
Monitoring Frequency	Fisher	0.0020	-	-	-
Magnitude of VOC Emission Rate – Wellheads					
Well Depth	Spearman	-	-	0.00956	0.3820
Eastern or Western US	Chi-Squared	0.00142	0.54	-	-
Basin	Fisher	0.0025	-	-	-
Monitoring Frequency	Fisher	0.0035	-	-	-
Oil Vs. Gas	Fisher	0.0005	-	-	-
Magnitude of VOC Emission Rate – Separators					
Host Operator	Fisher	0.0005	-	-	-
Basin	Fisher	0.0005	-	-	-
Monitoring Frequency	Fisher	0.0005	-	-	-
Operational Pressure	Spearman	-	-	0.0086	-0.2050
Oil Vs. Gas	Fisher	0.0005	-	-	-
Magnitude of VOC Emission Rate – Tanks					
Host Operator	Fisher	0.0005	-	-	-
Basin	Fisher	0.0005	-	-	-
Oil Production	Spearman	-	-	0.00106	0.332
Sitewide BOE/d	Spearman	-	-	0.000056	0.399

Among evaluated numeric variables, site equipment count also exhibited the strongest associations with both frequency and magnitude of sitewide emissions, exhibiting only a moderate positive correlation with detection frequency and weak associations with whole gas and methane emission rates. Weak correlations were also consistently detected among both the frequency and magnitude of emissions, total oil and gas production, and gas production rates. Figures B1 through B4 illustrate that these correlations are apparent among the data for total sitewide emissions for both gas sites and oil sites, respectively.

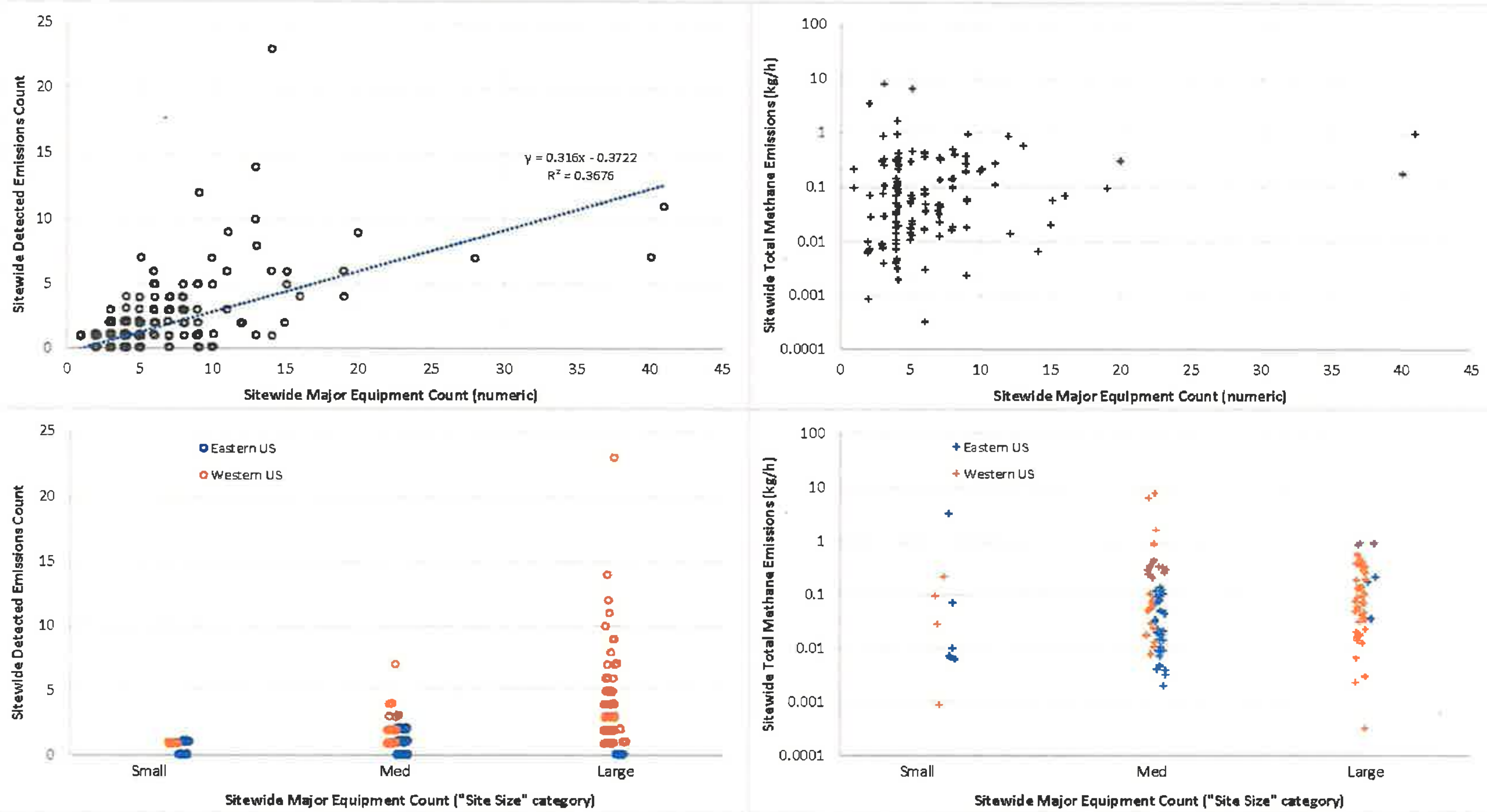

***Figure B1.** Magnitude and frequency of methane emissions compared to equipment counts at natural gas sites.*

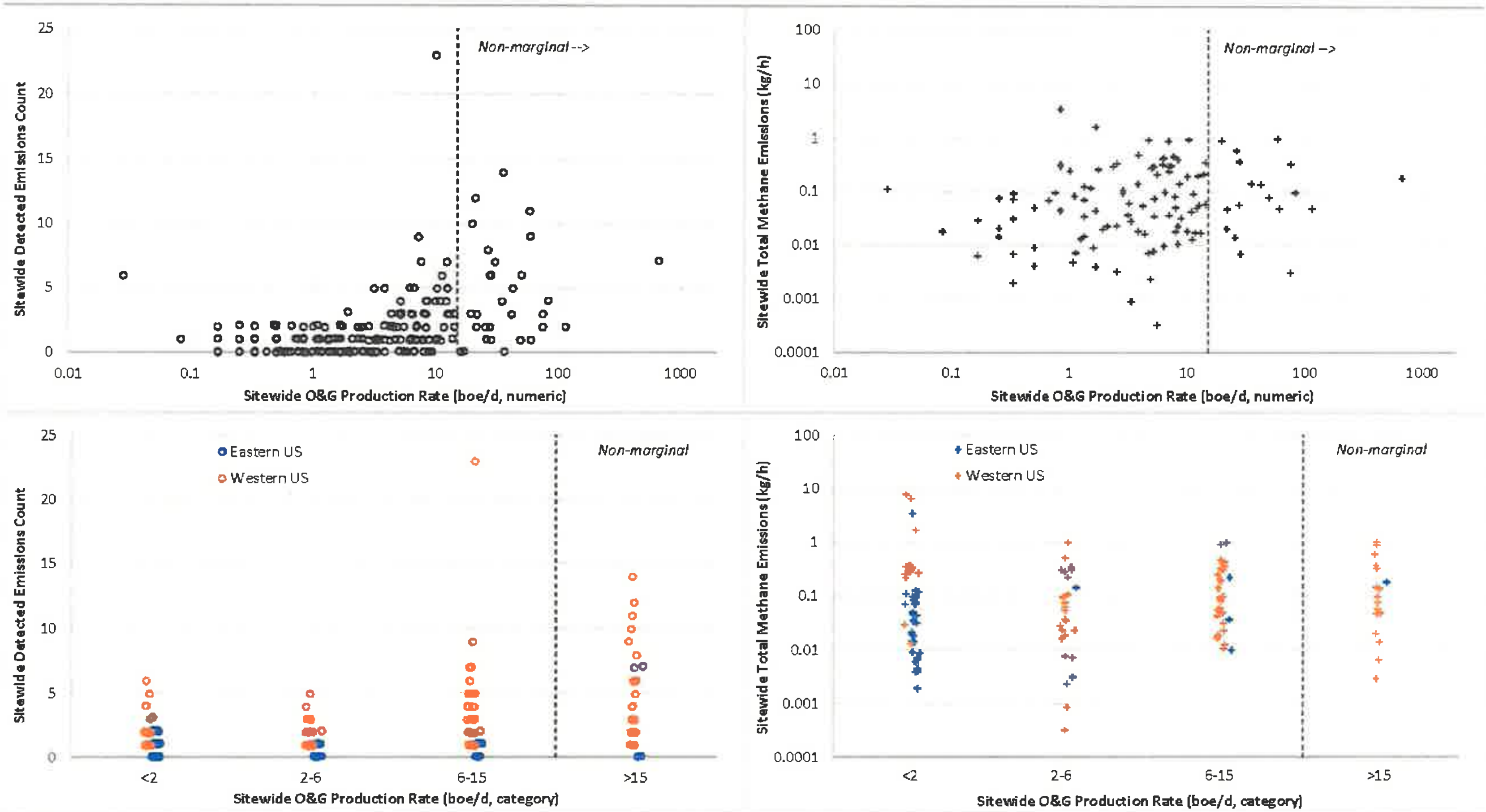

***Figure B2.** Magnitude and frequency of methane emissions compared to production rates at natural gas sites.*

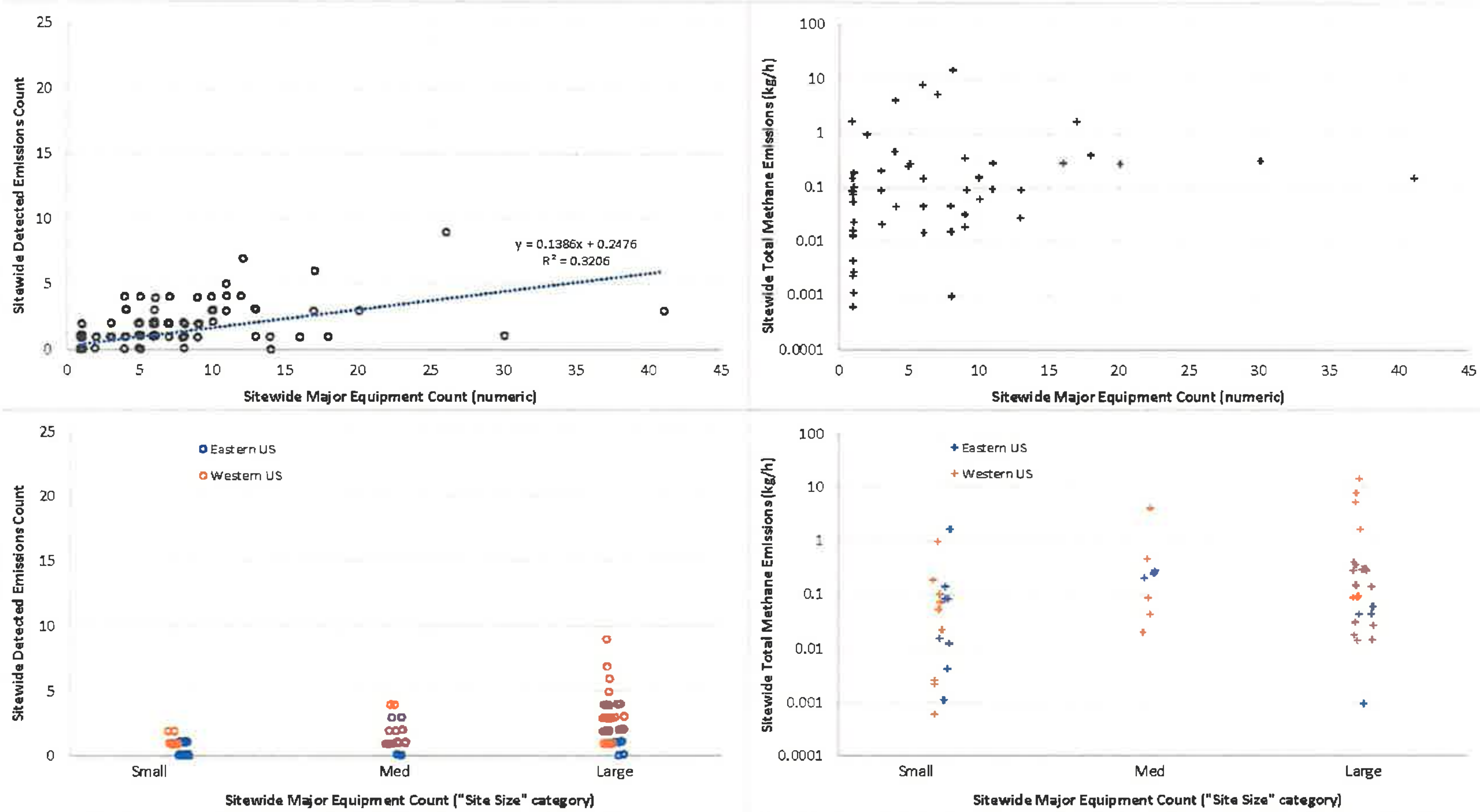

***Figure B3.** Magnitude and frequency of methane emissions compared to equipment counts at oil sites.*

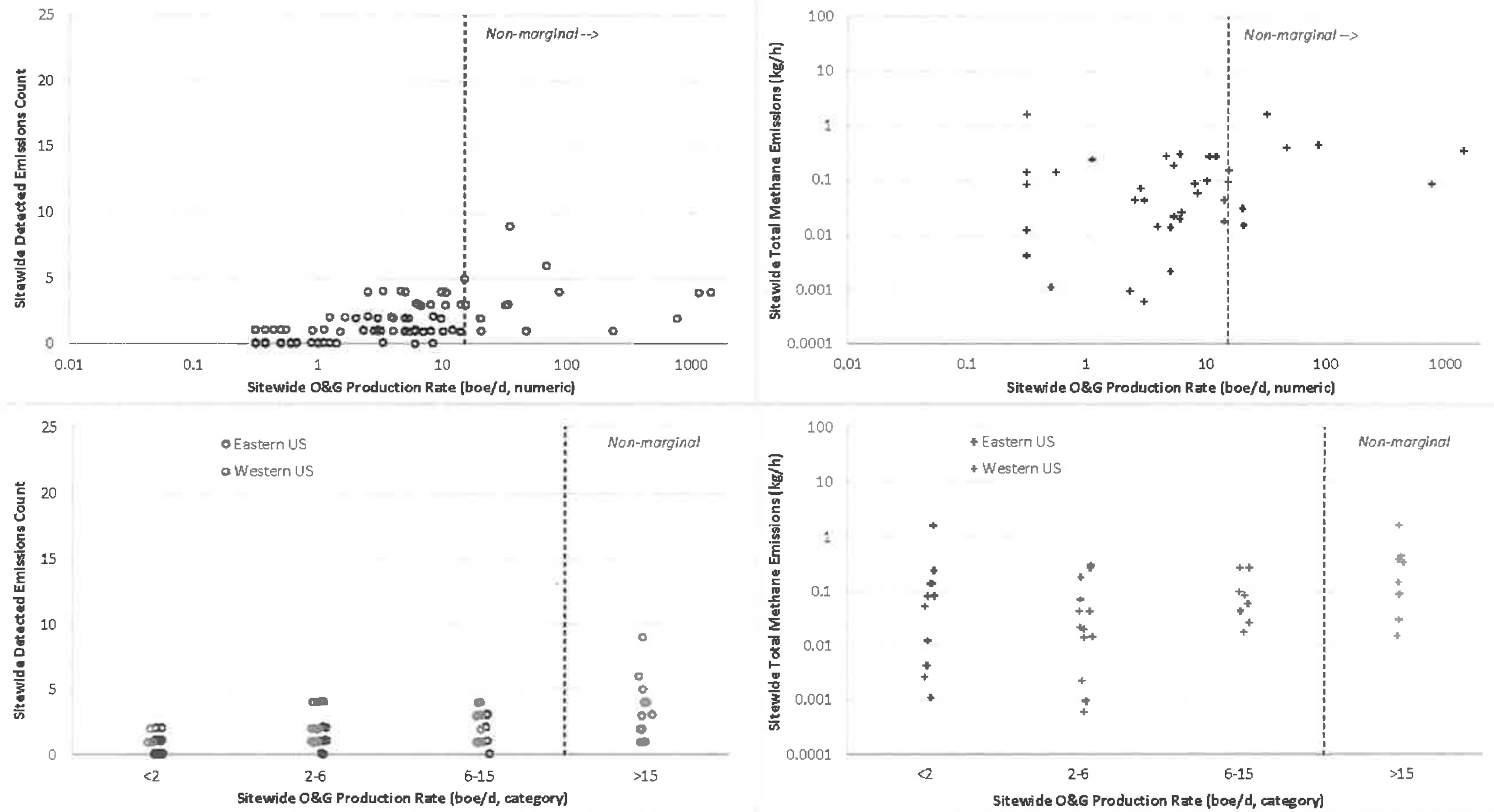

***Figure B4.** Magnitude and frequency of methane emissions compared to production rates at oil sites.*

36.22.1223 FENCING, SCREENING, AND NETTING OF PITS

(1) Open storage vessels, earthen pits, or ponds that contain oil must be fenced, screened, and netted.

(2) Open receptacles, earthen pits, or ponds that contain produced water ~~with more than 15,000 parts per million total dissolved solids~~ must be fenced, unless the surface owner agrees in writing, with the approval of the board or its representative, to waive this requirement.

(3) This rule does not apply to earthen pits used solely for the purpose of drilling, completing, recompleting, working over, or plugging a well.

Authorizing statute(s): 82-11-111, MCA

Implementing statute(s): 82-11-123, 82-11-124, MCA

History: NEW, 1992 MAR p. 654, Eff. 4/1/92.

6-11-2025 Objections by Somont Oil Company, Inc. to proposed rule change in ARM 36.22.1223 FENCING, SCREENING, AND NETTING OF PITS

Somont is a small family oil and gas producer and gas processor in the Kevin-Sunburst Field in northern Toole County with roots going back 100 years. We operate several hundred stripper oil wells and have around 100 evaporation pits scattered throughout about 300 square miles. Our primary oil producing horizon is the Madison Limestone which covers the Kevin Dome and is designated by the EPA (Environmental Protection Agency) as the nearest USDW (underground source of drinking water) in our area of operation as there is no potable ground water which is why it has been said that our part of the world would be an ideal place to bury nuclear waste. According to the EPA, a USDW is water containing less than 10,000 ppm (parts per million) of TDS (total dissolved solids).

In most instances, the amounts of water discharged by our tank batteries can be accommodated by small evaporation pits (most less than ½ acre) but in several cases the amount of water produced is too great to be contained in a reasonably sized evaporation pit and so in those instances we have obtained discharge permits from the Montana DEQ (Department of Environmental Quality) since the water we produce is of a suitable quality to be discharged into the ephemeral drainage area where it winds up in some of the alkali flats historic to the region which have native water far inferior to our produced water. Specifically, Madison water has a TDS content comfortably less than 5,000 ppm which enables it to meet the DEQ standard for suitability to be discharged into the ephemeral drainage area whereas the native standing water in the alkali flats from rain or snow runoff can easily have a TDS content well over 20,000 ppm. There is no question that any produced Madison water discharged into the ephemeral drainage area via a discharge permit is going from a superior water source to an inferior water source.

With regard to our evaporation pits, the majority of them have never been fenced because a) there is no livestock around or b) because the original lessor had stipulated that the pits were not to be fenced or c) because ranchers had requested that we not fence the pits because it was the primary source of drinking water for their livestock. Additionally, these pits are also the primary source of water for the substantial wildlife in the area. Those evaporation pits that were fenced would sometimes include the tank battery and sometimes there would be a separate fence around the tank battery.

In the case of our federal leases, we do have fences because that is required under the terms of all of our Federal leases.

On some of the fee leases where livestock can be present, we previously did have fences around our evaporation pits which sometimes would include the tank battery within the same fence. Over the years we did have livestock go through our fences on dozens of occasions and go into our pits to find water as we came to learn that if cattle are thirsty, they will go through pretty much any fence. When that happened, and we discovered it, we would shoo the cattle out and put the fences back up.

Nearly all of our properties on which we either own or lease the minerals are split estates, which means that in most cases we do not own the surface. **But since minerals have primacy in Montana, we do have the right under our mineral leases to use as much of the surface estate as reasonably necessary to conduct our operations. So in the relationship between the rancher and the oilman, that means that the evaporation pits are the oilman's property and if the rancher's livestock goes into the evaporation pits, they are trespassing.**

The area of Toole County in which we operate is "open range" country and what that basically means in the relationship between the rancher and the oilman with regard to fencing is that there is no requirement for anybody to put up fences. If nobody puts up fences and the livestock trespass onto the oilman's property (such as going into an evaporation pit) and causes damage to either the oilman's property or to the cattle themselves, there is no absolute liability attached for either party. On the other hand, if the oilman puts up fences to keep the cattle out of his property, then the rancher is theoretically liable for any damage his trespassing cattle cause to the oilman's property although in 50 years I do not recall a single occasion when we have sought or collected a dime from any ranchers for damages caused to our fenced operations from their trespassing livestock. **The ironic exception to this, which we learned to our sorrow, is that if the oilman puts up fences and they are not deemed to be "legal" as defined in MCA 81-4-101, then the oilman has absolute liability (meaning 100% liability) for any harm that the cattle cause to themselves even if they are trespassing.**

We learned this sad lesson in 2014 when a local rancher's cattle went through Somont's fences several times during the year in search of water and Somont put them back up when the breach was discovered. But on one occasion they kicked open an oil valve at the bottom of the stock tank which drained oil into the evaporation pit which was ingested by the cattle and wound up killing a number of them. This was the "Stene" case which ultimately resulted in a $700,000 judgment against Somont in 2019 because we could not "prove" to a Toole County jury that the fences had been legal at the time the cattle went through them since the only evidence of the fences' condition were pictures of the mangled posts and barbed wire taken after the cattle had completely wrecked them.

Following the judgment, we reasoned that since we could not control how well or poorly any rancher took care of his livestock, it would be crazy for us to risk another such incident in the future which could bankrupt us and so we contacted all of the known ranchers on all of our leases and told them that we were going to take down all of the fences around our evaporation pits but did offer to gift them the fencing if they wanted to take ownership. In that way, if they owned the fencing and their cattle went through it, we would not have absolute liability for whatever harm might befall them.

Some of the ranchers accepted the offer but four, including the Scott Bye family, the Korey Fauque family, and the families of State Senator Butch Gillespie and his brother Wayne Gillespie took the position that on any of their properties on which we currently had fencing, we were legally required to keep and maintain them and that formed the basis for a lawsuit that they filed in early 2020 (DV-20-018) which included a TRO (Temporary Restraining Order) requiring us to keep our fencing in place throughout the pendency of the litigation. The original lawsuit only related to a dozen or so pits on their property that were fenced and did not include the half dozen or so unfenced pits on their property. Their steadfast position, despite specific evidence to the contrary, was that they were good ranchers and always took care of their livestock and kept them properly watered and fed and, therefore, their cattle would never go through legal fences to get into our evaporation pits.

Putting things in perspective, with the Stene case being an anomaly that cannot be repeated (since tank batteries remain fenced apart from the evaporation pits), over the past 50 years the Plaintiffs in the lawsuit have collectively been able to identify 1 and possibly 2 instances where a single cow or calf died in one of our evaporation pits whether fenced or unfenced.

We appealed the TRO to the Supreme Court and after four years it was unanimously reversed last summer (Decision DA 22-0707 2024 MT 130N attached) which enabled us to remove all of the fencing around the evaporation pits on the Plaintiffs' properties – after again offering to gift them the fencing if they wanted to assume ownership.

The Supreme Court ruling essentially rendered the original lawsuit pointless but Plaintiffs have recently amended their initial complaint to expand on, among other things, damages to their livestock and land from water leaving the pits along with an alleged violation of the Federal Clean Water Act. Their introduction of the Federal Clean Water Act enabled us to move the case from State District Court to Federal District Court where it now is proceeding. Since that time we have also been investigated thoroughly by MBOG inspectors and DEQ inspectors responding to a number of complaints from the same Plaintiffs regarding our operations, all of which we have addressed and resolved to the satisfaction of the inspectors so far as I am aware.

There is little, if anything, in the 88 pages of Plaintiffs' April submission to this Board that has not already been introduced and is being addressed in the pending litigation and we will certainly address it again in this forum as appropriate as and if this proposed rule change moves forward. But one general observation I will make at this time on the submission is that the depiction of the alleged damage caused by "leaking pits" is grossly mischaracterized. Many of the pits long predate our acquisition but with regard to those we have put in ourselves and the pre-existing ones which we have taken over from previous operators, there have been very few occasions where they have overflowed. And when they do, it is generally due to the livestock and wildlife going into the pits for water (whether the pit was fenced at the time, as in the past, or whether unfenced) and eroding a berm which creates a low spot for the water to leak out, which is repaired as soon as we find it or it is called to our attention.

The motivation behind the proposed rule change is the same as the motivation behind the current lawsuit which has been to make the oilman responsible (with absolute liability) for keeping the livestock belonging to the four Plaintiffs from trespassing onto the oilman's property. Since the lawsuit is not going particularly well for the Plaintiffs, following up on comments made five years ago when the current lawsuit was initiated, Plaintiffs are now seeking to use their political influence to change the rules which they have been unable so far to do in the court.

I am aware of no rational reason for requiring the oilman to fence evaporation pits that contain produced water of sufficient quality to be discharged into the ephemeral drainage area, bearing in mind that if ranchers are truly concerned about not wanting their livestock to trespass into evaporation pits, they have an extremely simple solution which is to put up fences of their own and be responsible for them. I do note in the year since we were able to take our fences down, I am not aware of the Plaintiffs putting any fences back up although we have observed some cattle belonging to the Plaintiffs walking about in one of our evaporation pits with empty water troughs belonging to the Plaintiffs sitting outside the pit suggesting that the Plaintiffs may not think the water in the evaporation pits is as bad as they are claiming.

In considering the proposed rule change, I do want to offer my unscientific opinion as to why the existing rule has the fencing requirement only for water with TDS amounts over 15,000 which is based on nothing but my experiences as an operator as I had never thought about it before.

I go back to the fact that the EPA definition of a USDW is an aquifer that contains fewer than 10,000 ppm of TDS. So my guess is that the background for the 15,000 ppm limit for unfenced pits was based on recognition by the previous rule makers that evaporating water and precipitation both have minimal TDS content. Thus, in an evaporation pit as the water evaporates the concentration of TDS in the remaining pit water <u>increases</u> and as rain and snow get into the pit, the concentration of TDS in the remaining pit water <u>decreases</u> and so the 15,000 ppm limit was in recognition of the fluctuations caused to the TDS content in evaporation pits containing produced water. This would not apply to water discharged into the ephemeral drainage area because under that scenario the TDS content of the water leaving the tank battery would be virtually identical to the TDS content of the water going into the ephemeral drainage area.

Charles Jansky – somontoil@gmail.com; O-281-251-4398; C-713-410-7705

FILED
06/18/2024
Bowen Greenwood
CLERK OF THE SUPREME COURT
STATE OF MONTANA
Case Number: DA 22-0707

DA 22-0707

IN THE SUPREME COURT OF THE STATE OF MONTANA

2024 MT 130N

SCOTT AND PAMELA BYE;
KOREY AND WENDY FAUQUE;
BUTCH AND DOREEN GILLESPIE;
WAYNE AND ROXY GILLESPIE; and
JOHN DOES 1, 2, 3, 4,

Plaintiffs and Appellees

v.

SOMONT OIL COMPANY, INC.

Defendant and Appellant.

APPEAL FROM: District Court of the Ninth Judicial District,
In and For the County of Toole, Cause No. DV-20-018
Honorable Kaydee Snipes Ruiz, Presiding Judge

COUNSEL OF RECORD:

For Appellant:

Gregory J. Hatley, Stephanie A. Hollar, Davis, Hatley, Hafferman & Tighe, P.C., Great Falls, Montana

For Appellees:

Hertha L. Lund, Christopher T. Scoones, Ben F. Stormes, Lund Law, PLLC, Bozeman, Montana

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Submitted on Briefs: June 21, 2023

Decided: June 18, 2024

Filed:

Clerk

Justice Dirk Sandefur delivered the Opinion of the Court.

¶1 Pursuant to Section I, Paragraph 3(c), Montana Supreme Court Internal Operating Rules, we decide this case by memorandum opinion. It is not precedent and shall not be cited as such. The case title, cause number, and disposition shall be included in our quarterly list of noncitable cases published in the Pacific Reporter and Montana Reports.

¶2 Defendant Somont Oil Company (Somont) appeals from the November 2022 Amended Order Granting Preliminary Injunction issued by the Ninth Judicial District Court in favor of Plaintiffs Scott and Pamela Bye, Korey and Wendy Fauque, Butch and Doreen Gillespie, and Wayne and Roxy Gillespie (Landowners). We reverse.

¶3 Somont operates oil and natural gas production sites under owned or leased mineral rights in otherwise privately owned ranch and farm lands in the vicinity of Kevin, Oilmont, and Shelby, Montana. Historically, Somont voluntarily maintained fencing around its various oil and gas production facilities (*inter alia* including pump jacks, tank batteries, skim pits, and water evaporation pits) to fence-out livestock and trespassers. In July 2019, a Toole County jury awarded another landowner, (Stene), compensatory damages ($697,671.45) pursuant to § 81-4-103, MCA, for cattle injury or loss caused by Somont's failure to maintain its voluntary facility fencing in accordance with the "legal fence" specifications for livestock containment set forth in § 81-4-101, MCA. *Stene v. Somont*, DV-16-137, Mont. Ninth Judicial Dist. Court. The subject cattle losses resulted from cattle drinking oil-contaminated water from one or more Somont water evaporation pits.

¶4 In the wake of the *Stene* judgment, Somont notified affected surface landowners that it planned to remove its water evaporation pit fencing on the ground that, as manifest in *Stene*, voluntary fencing exposed it to potential strict liability under §§ 81-4-101 and -103, MCA. As an alternative to removal, Somont offered to gift existing evaporation pit fencing to the owners of those properties in return for their assumption of responsibility for fence maintenance. Several other landowners not party to this litigation accepted the offer, but Plaintiff Landowners did not. They instead sued Somont for declaratory judgment, compensatory damages, and injunctive relief enjoining it from removing any of the subject fencing. At the core of those claims, Landowners asserted that Somont had alleged statutory, common law, and contract duties to fence all of its oil and gas production sites to protect Landowners' stock from harm.

¶5 In 2020, after granting Landowners' request for a temporary restraining order pending a hearing on their accompanying request for a preliminary injunction, the District Court conducted a hearing and ultimately granted the requested preliminary injunction enjoining Somont from removing fencing around any of its production facilities on Landowners' properties. Without addressing the distinct disjunctive criteria for issuance of a preliminary injunction under § 27-19-201(1)-(3), MCA (2019-21), or making any particularized findings of fact on the hearing record regarding any of those criteria, the District Court summarily concluded that the "parties' briefing and [hearing] evidence" indicated that the requested preliminary injunction was "proper" based on "[t]he balance of hardships," "irreparable injury[,] and probability of victory after trial." On Somont's interlocutory appeal, we held that the District Court's failure to make particularized findings of fact and conclusions of law regarding any of the alternative criteria for issuance of a preliminary injunction under § 27-19-201(1)-(3), MCA, made it:

> impossible to evaluate how the District Court appraised the Landowners' and Somont's legal theories or how it balanced the interests of the parties, including the hardship Somont might face and any irreparable injury to the Landowners. Without proper findings of fact and conclusions of law, this Court lacks an adequate basis on which to review the District Court's reasoning. . . . [W]e are [thus] unable to determine whether the District Court abused its discretion in granting . . . [a] preliminary injunction under [§ 27-19-201(1), (2), or (3), MCA].

Bye v. Somont Oil Co., Inc. (*Somont I*), 2021 MT 271N, ¶ 18, 407 Mont. 2, 497 P.3d 275. We thus reversed and remanded "for the District Court to issue findings of fact and conclusions of law supporting its issuance of the preliminary injunction." *Somont I*, ¶ 19.

¶6 In November 2022, the District Court accordingly issued amended findings of fact, conclusions of law, and an order granting the requested preliminary injunction on the sole basis of § 27-19-201(2), MCA (2019-21) (requiring a showing "that commission or continuance of some act during the litigation would produce a great or irreparable injury to the applicant"). In pertinent part, the court found that:

> (1) Landowner Wayne Gillespie testified that poor fencing has already killed one calf and possibly another . . . in March 2020;
>
> (2) Landowners Gillespie and Bye stated that "well maintained fences are effective at keeping out cattle" and that "they will lose livestock" "if Somont remove[s] its protective fence" because "many of Somont's pits pose a real danger" to cattle;
>
> (3) area rancher Charles Jansky testified that: (A) "cattle were not usually injured or killed in the evaporation pits" "until the *Stene* case"; (B) "he believed that cattle had gotten through the [Somont] fences 3 dozen times in the last 30

years"; (C) "there was an accident 10 or 12 years ago involving a [Gillespie] cow" and the "recent cow's death revealed at the show cause hearing"; and (D) that "he thought removing the fences would make it more likely that cattle will get into the pits" . . . "[d]epend[ing] on how good the rancher [is] who's taking care of [th]em";

(4) Landowners have thus "produced evidence that removal of the fencing *could* cause even more problems, great injury, or irreparable harm to [them]";

(5) "losing cattle is a great injury" to Landowners and "losing necessary fencing and potentially replacing existing fencing while awaiting the outcome" of this case "*could* cause great or irreparable injury" to Landowners which "cannot be fully or effectively remedied by compensatory damages"; and

(6) "[t]here would appear to be minimal hardship for Somont to maintain" its existing evaporation pit fencing "along with [other] fencing it desires to keep in use."

(Emphasis added.) The District Court thus ultimately found and concluded that Landowners satisfied the criteria specified in § 27-19-201(2), MCA (2019-21). Somont timely appealed.

¶7 We review district court grants or denials of injunctive relief for a manifest abuse of discretion. *Shammel v. Canyon Resources Corp.*, 2003 MT 372, ¶¶ 11-12, 319 Mont. 132, 82 P.3d 912. An abuse of discretion occurs if a lower court exercises lawful discretion based on a clearly erroneous finding of material fact, an erroneous conclusion of application of law, or otherwise acts arbitrarily, without conscientious judgment or in excess of the bounds of reason, resulting in substantial injustice. *In re Marriage of Bessette*, 2019 MT 35, ¶ 13, 394 Mont. 262, 434 P.3d 894; *Larson v. State*, 2019 MT 28, ¶ 16, 394 Mont. 167, 434 P.3d 241. We review conclusions and applications of law de novo for correctness. *Williams v. Zortman Min., Inc.*, 275 Mont. 510, 512, 914 P.2d

971, 972-73 (1996); *Carbon Cnty. v. Union Rsrv. Coal Co.*, 271 Mont. 459, 469, 898 P.2d 680, 686 (1995). A lower court finding of fact is clearly erroneous if not supported by substantial evidence, the lower court clearly misapprehended the effect of the evidence, or, upon our independent review of the record, we are definitely and firmly convinced that the court was otherwise mistaken. *Interstate Prod. Credit Ass'n v. DeSaye*, 250 Mont. 320, 323, 820 P.2d 1285, 1287 (1991). "A manifest abuse of discretion is one that is obvious, evident, or unmistakable." *Shammel*, ¶ 12.

¶8 As pertinent here, a district court has discretion to grant a preliminary injunction only upon a prima facie showing "that commission or continuance of some act during the litigation would produce a great or irreparable injury to the applicant" "*prior to final resolution on the merits*." Section 27-19-201(2), MCA (2019-21); *Davis v. Westphal*, 2017 MT 276, ¶ 24, 389 Mont. 251, 405 P.3d 73 (citations omitted—emphasis original). Only then is a preliminary injunction proper for the purpose of "preserv[ing] the status quo and minimiz[ing]" the threatened harm. *Davis*, ¶ 24 (citation omitted).[1] At equity, as codified in § 27-19-201(2), MCA (2019-21), "great or irreparable injury" "is a harm or wrong" either:

(1) not fully or effectively remedied by compensatory damages;[2]

[1] In the preliminary injunction context, the "*status quo* is generally the last actual, peaceable, [and] uncontested condition preceding the controversy at issue." *Davis*, ¶ 24 (quoting *Porter v. K & S Partnership*, 192 Mont. 175, 181, 627 P.2d 836, 839 (1981)—internal punctuation omitted and emphasis added).

[2] "A statutory or common law remedy may be inadequate to fully or effectively remedy a harm or wrong either due to the nature of the cause of action or the form of relief ordinarily available thereon." *Davis*, ¶ 26 (citation omitted).

(2) in regard to which adequate, non-speculative compensation is difficult to determine; or
(3) of a recurring or continuous nature such that full and effective redress would otherwise require a multiplicity of successive actions at law.

Davis, ¶ 26 (citation omitted). Thus, as noted in *Somont I*, ¶ 17, preliminary injunctive relief is generally *not* available absent a showing that an available compensatory damages remedy will be insufficient to provide complete relief. *Davis*, ¶¶ 26-27 (citations omitted); *Dicken v. Shaw*, 255 Mont. 231, 236, 841 P.2d 1126, 1129 (1992) (economic harm compensable by money damages is generally not "irreparable harm" for purposes of equity analysis under § 27-19-201(2), MCA (2019-21); *Van Loan v. Van Loan*, 271 Mont. 176, 183-85, 895 P.2d 614, 618-19 (1995) (economic harm compensable by money damages generally not "irreparable harm" absent showing of unique circumstances that "would render . . . money judgment ineffectual" such as showing of defendant intent or action "to make" self "judgment proof"). *See also BAM Ventures, LLC v. Schifferman*, 2019 MT 67, ¶¶ 16-18, 395 Mont. 160, 437 P.3d 142 (holding that district court correctly found that ultimate money damages recovery would not adequately compensate applicant for interim cessation of status quo use of disputed prescriptive easement for access to and from applicant's property). Consideration or balancing of the relative equities or burdens attendant to requested preliminary injunctive relief is proper under § 27-19-201(2), MCA (2019-21), only upon the requisite prima facie showing of great or irreparable harm. *Van Loan*, 271 Mont. at 180-82, 895 P.2d at 616-17 (applicant must show "likelihood" of irreparable harm and that "balancing of the equities" favors injunction). *Accord Shammel*, ¶ 17 (quoting *Van Loan*, 271 Mont. at 182, 895 P.2d at 617); *Citizens for Balanced Use v.*

Maurier, 2013 MT 166, ¶¶ 23-28, 370 Mont. 410, 303 P.3d 794 (holding that court erroneously granted preliminary injunction under § 27-19-201(2), MCA (2019-21), upon "balancing of the equities" "even though [applicant] failed to demonstrate likelihood of irreparable injury" absent injunction).

¶9 Here, as a matter of law, and as reflected in Landowners' asserted claims for relief, the risk of future cattle loss that "could" result from Somont's planned removal of its voluntary water evaporation pond fencing on Landowners' respective properties is compensable by money damages upon showing of the asserted statutory, common law, and/or contract duties of care, and accompanying proof of breach, causation, and damages. In that regard, Landowners made no evidentiary showing that any such economic loss would be extraordinarily difficult to determine or prove. Nor have they made any evidentiary showing that any such compensable loss would likely be of such a recurring or continuous nature in the limited time prior to final disposition to either preclude or impair full monetary compensation or require a multiplicity of successive lawsuits. Thus, the District Court's ultimate finding, that Landowners produced evidence that removal of the subject Somont fencing "could cause great or irreparable injury," as defined in *Davis*, ¶ 26, is clearly erroneous. As an even more fundamental matter, moreover, the Court's essential finding that removal of the subject fencing "*could* cause great or irreparable injury" (emphasis added) is an expressly speculative finding that falls short of the § 27-19-201(2), MCA (2019-21), requirement for a prime facie showing, and corresponding finding, of a *likelihood* of the asserted harm. *See Davis*, ¶ 24; *Shammel*, ¶ 17 (quoting *Van Loan*, 271 Mont. at 182, 895 P.2d at 617).

¶10 Landowners alternatively assert that the requested preliminary injunction was nonetheless warranted under § 27-19-201(1) or (3), MCA (2019-21) (showing that applicant is "entitled to the relief demanded" or that "adverse party is doing or threatens or is about to do or is procuring or suffering to be done some act in violation of the applicant's rights . . . tending to render" an ultimate successful "judgment ineffectual"). In the context of our remand instruction, and the District Court's sole focus on § 27-19-201(2), MCA (2019-21), Landowners thus essentially assert that the court erroneously failed to grant the requested injunction under § 27-19-201(1) or (3), MCA (2019-21). They have not demonstrated, as a matter of law or prima facie fact, however, that Somont has an affirmative legal duty to fence their subject evaporation ponds, apart from liability to compensate for any non-speculative harm caused by a breach of an applicable legal duty of care. *See* § 27-19-201(1), MCA (2019-21). Nor have they made a prima facie showing that Somont "is doing[,]" threatening, or "about to do or is procuring or suffering to be done some act in violation of the applicant's rights" *that would "tend[] to render" an ultimate successful "judgment ineffectual."* *See* § 27-19-201(3), MCA (2019-21) (emphasis added).

¶11 This case is decided by memorandum opinion pursuant to Section I, Paragraph 3(c) of our Internal Operating Rules. For the foregoing reasons, we hold that the District Court manifestly abused its discretion in granting Landowners the subject preliminary injunction.

The District Court's November 2022 Amended Order Granting Preliminary Injunction is hereby reversed, and this matter is remanded for adjudication of Landowners' other asserted claims in the ordinary course.

/S/ DIRK M. SANDEFUR

We concur:

/S/ MIKE McGRATH
/S/ LAURIE McKINNON
/S/ INGRID GUSTAFSON
/S/ JIM RICE

Petition to Fence Production Water Pits

EXHIBIT 5

A Petition of Northern Montana farmers, ranchers and citizens

Addressed to Montana Board of Oil and Gas Conservation

We, the undersigned, are concerned citizens who would like to bring your attention to the following problem, with recommendation(s):

We support changing the MBOGC policy for fencing of production water pits to state "any permanent evaporation pit containing production water must be fenced". We believe it should be the duty of the entity creating the production water pit to fence out livestock and wildlife from the pits they have created.

PRINTED NAME	SIGNATURE	ADDRESS	COMMENT	DATE
G. Michael Ehlers	[illegible]	33 Frank Coulee Ln [illegible] MT		02/18/2025
Laura Wickum	[illegible]	100 Hagen Rd Shelby MT 59474		2-18-2025
Robert Pace	[illegible]	Sunburst, MT		2-18-2025
Roslyn Pace	[illegible]	Sunburst, MT		2-18-2025
Casey Nord	[illegible]	Shelby MT		2-18-25
Matthew Tonsfeldt	[illegible]	Sunburst MT		2-18-25
Terry Alm	Tery Alm	857 Oilmont Hwy Oilmont MT		2-18-25
T&C Alm Inc	by T Alm President	//		2-18-25
Joseph Pehan	Joseph Pehan	Bx 166 Shelby MT		2-18-25
Patrick Simons	Patrick Simons	Shelby, MT		2-18-25
Barbara Larsen	Barbara C Larsen	Box 116 Galata MT 59444		2-18-25
Joe R Larsen	Joe R Larsen	Box 116 Galata MT 59444		2-18-25
Darold Tonsfeldt	[illegible]	Box 134 Sunburst, MT 59482		2-18-25
Fredrick Fairhurst	Fredrick Fairhurst	396 Holtz Rd, Sunburst 59482		02/18/2025
William Wiegand	William Wiegand	Box 428 Shelby 59474		2-18-25

Petition to Fence Production Water Pits

A Petition of Northern Montana farmers, ranchers and citizens

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PRINTED NAME	SIGNATURE	ADDRESS	COMMENT	DATE
Nathan C Aschim	[illegible]	347 Aschim Rd Sunburst MT 59482		2/18/25
Philip O. Aschim	[illegible]	343 Aschim Road 59482		2/18/25
Cole Kleinert	[illegible]	131 Dry Teplette Rd Sunburst, MT 59482		2-18-25
Rex L Tomsheck	[illegible]	43 Pleasant View Farm Ln Oilmont		2/18/25
Chuck Kelleher				2/18/25
Jabez Rogers	[illegible]			2/18/2025
Owen Marshall	[illegible]	858 Gus Blaze Rd, Shelby MT 59474		2/18/2025
Kyle Watterud	[illegible]			2/18/25
Derek Sisk	[illegible]			2-18-25
Lane Leum	[illegible]	PO Box 42, Galata, MT, 59444		2-18-25
Dean Leum	Den Lum	Box 56 Galata, MT 59444		2-18-25
Klayton Lohr	Klayton Lohr	6 Lohr Rd Shelby, MT 59474		2/18/25
Zach Johannsen	[illegible]	69 Johannsen Rd Shelby, MT 59474		2/18/25
JAY JOHANNSEN	[illegible]	69 Johannsen Rd. Shelby, Mt. 59474		2/18/25
Scotty Bye	[illegible]	31 Bye Rd Kevin, Mt 59454		2-18-25
Troy Wanken	[illegible]	Box 571 Shelby MT 59474		2-18-25

Petition to Fence Production Water Pits

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PRINTED NAME	SIGNATURE	ADDRESS	COMMENT	DATE
Mark Robertson	Mark Robertson	Shelby MT 300 Robertson Road		2-18-25
Donna Griffin	Donna Griffin	260 2800 Rd S Galata mt		2-18-25
Jake Wiegand	J. Wiegand	133 Hill Ave Shelby		2-18-25
Chris Kimmet	Chris Kimmet	48 Zell Farm RD Shelby		2-18/25
Michael Deaku	[illegible]	111 Mahrese Rd Ledger MT		2/18/25
Jeff Dow	Jeff Dow			2/18/25
Ben Ehlers	Ben	33 Riverside Cordel [illegible] Kilmont		2-19-25
Jim Nagy	Jim Nagy	P.O. Box 89 Sweet Grass		2-19-25
Jeanne Nagy	Jeanne Nagy	PO Box 89 Sweet Grass MT 59484		2-19-25
Kaden Keith	Kaden Keith	P.O. Box 301 Sunburst MT 59482		2-19-25
Jackson Nagy	J. E. Nagy	1263 Border RD Sweet Grass, MT 59484		2-19-25
DAVE SANDON	David Sandon	Box 56 Sunburst Mt 59482		2-19/25
Adrian Hawks	Adrian Hawks	5501 [illegible] Road Galata Mt. 59444		2-19-25
[illegible]	[illegible]	Galata MT 59444		2-19-25
Carl Flesch	Carl Flesch	811 Hill Ave Shelby MT 59474		2/19/25

Petition to Fence Production Water Pits

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PRINTED NAME	SIGNATURE	ADDRESS	COMMENT	DATE
[illegible]	[illegible]	27 Cec. 1 Dr Shelby MT		2/19/25
Justin [illegible]	[illegible]			2/19/25
Fay Tomayer	Fay Tomayer	Galata		2/19/25
Ken Tomayer	Ken Tomayer	Galata		2/19/25
Roger Hongus	[illegible]	Sweetgrass		2/19/25
Richie Suta	Richie Suta	Sunburst		2/19/25
Chris Suta	[illegible]	Sunburst		2-19-25

MBOGC Pit Fencing Hearing

June 11th, 2025

Water Test Result:	Comments	Sources of Contamination	Acceptable Levels or Expected Ranges by Source: Summary Recommendations (Oetzel)	EPA (human standards)	Dairy NRC 2001	Canadian Task Force, 1987	Jim Linn's Review Paper, 1991 Four-State Conf.	John Parsen, UW SPAL Info Sheet, ~1991	Dairyland Labs (10/11/01)	Dairyland Labs (12/05)	Rock River Labs* (6/25/04)	Mike Socha - DHM article (10/01)	Comments, Other Sources
Index Measures:													
pH	Only EPA info available; no cow studies have been done. Low pH (<6) causes corrosiveness and gives water a metallic taste. High pH gives the water a slippery feel, soda taste, and leaves deposits.		6.0 to 9.0	6.5 to 8.5 (secondary)	6.5 to 8.5				<8.3	5.5 to 8.3	<8.5		
Corrosivity	Corrosive water corrodes pipes and fixtures, causes staining, and adds a metallic taste to the water.	Low pH water, other factors? There are specific testing procedures for water corrosivity (EPA).	---	Non-corrosive (secondary)									
Salinity, TDS, TSS	Mostly from NaCl; bicarbonate, sulfate, Ca, Mg, and silica may also contribute. May add color to the water and reduce water intake. Gives water a salty taste.		<1000 ppm	<500 ppm (secondary)	<1000 safe, 1000-2999 can be used	<3000 ppm			<1000 ppm		<960 to 5000 ppm*		
Hardness	Sum of Ca and Mg; reported as equivalent amount of $CaCO_3$; hard water may clog pipes over time. Hard water leaves scaly deposits on plumbing and fixtures. Hard water also decreases the cleaning action of soaps and detergents. Hard waters may be more palatable than soft waters.	Naturally dissolved Ca and Mg from soil and limestone.	---	no EPA limit			0-60 ppm is soft, 61-120 is moderate, 121-180 is hard, and >180 ppm is very hard; 1 grain/gallon equals 17.1 ppm.				<44 ppm		
Alkalinity	Measured as the capacity of water to buffer acid; high alkalinity is associated with high pH. High alkalinity waters may have a distinctly flat, unpleasant taste.	Alkalinity comes from carbonates, bicarbonates, and hydroxides dissolved in the water.	<500 ppm	no EPA limit		>500 ppm has a laxative effect							Buffers low pH waters to reduce corrosion
Nitrate-nitrogen	Toxic to infants less than 6 months of age; causes shortness of breath and blue-baby syndrome.	Runoff from fertilizer use; leaching from septic tanks; sewage; erosion of natural deposits.	<25 ppm	<10 ppm (legal)	<10 ppm		<100 ppm	Public water should not exceed 10 ppm	<50 ppm		<10 to 20 ppm*	<25 ppm	
Nitrite-nitrogen	Same toxicity as nitrate	Runoff from fertilizer use; leaching from septic tanks; sewage; erosion of natural deposits.	<10 ppm	<1 ppm (legal)			<10 ppm						
Ammonia-nitrogen	An indication of pollution		---	no EPA limit				Public water should not exceed .5 ppm					
Sulfates	>150 ppm causes noticeable salty taste. Sulfate salts are laxatives, with Na_2SO_4 the most potent laxative. H_2S is the most toxic form of S (formed on anode rod of hot water heater or by iron bacteria). SO_4 is 33% S.		<250 ppm	<250 ppm (secondary)	<500 ppm calves and <1000 ppm adult cows	<1000 ppm	<500 ppm calves and <1000 ppm adult cows	Public water should be <250 ppm due to taste and laxative effects	<300 ppm	<300 ppm		<125 ppm	>200 ppm may cause odors, taste bitter, and have a temporary laxative effect.
Microminerals:													
Aluminum	May add color to the water; no health effects listed (EPA).		<5 ppm	<.05 to .20 ppm (secondary)	<.5 ppm	<5 ppm	<5 ppm	Rarely >.2 ppm			<5 to 10 ppm*		
Arsenic	Causes skin damage, circulatory system problems, and increased risk of cancer.	Erosion of natural deposits; runoff from orchards; runoff from glass and electronics production wastes.	<.2 ppm	<.05 ppm (legal)	<.05 ppm	<.50 ppm	<.20 ppm	Range of .005 to .34 ppm; median of .06 ppm			<.20 ppm		
Boron			---	no EPA limit	<5 ppm	<5 ppm	<5 ppm				<5 to 1000 ppm*		
Cadmium	Toxicity causes repro problems, possible anemia; EPA lists kidney damage in humans.	Corrosion of galvanized pipes; erosion of natural deposits; discharge from metal refineries; runoff from waste batteries and paints.	<.05 ppm	<.005 ppm (legal)	<.005 ppm	<.02 ppm	<.05 ppm				<.01 to .05 ppm*		
Chromium	Toxicity causes skin and soft tissue problems; EPA lists allergic dermatitis.	Rarely found in natural waters; indicates industrial pollution (runoff from steel and pulp mills); erosion of natural deposits.	<1 ppm	<.1 ppm (legal)	<.1 ppm	<1 ppm	<1 ppm				<.1 to 1 ppm*		

Ahlstead Lease

Aronow Lease

Smith Lease

Van Note

	A	B	C	D	E	F	G	H	I	J	K	L
1					Korey Fangue Readings			Energy Laboratory Readings				
2	Tank Battery/ Lease Name	Sample Number	Sample Date	Time	Nitrate (PPM)	TDS (PPM)	Salinity (PPM)	Nitrate (PPM)	TDS (PPM)	Sodium (PPM)	Sulphate (PPM)	PH
3	Ahlstead	2201107	8/27/2024	10:43 AM	50	7320	6400	NA	6960	2300	2150	9.2
4	Anna Aronow	2201106	8/27/2024	1:28 PM	78	6800	5800	0.01	5930	2190	573	9.7
5	Bruns	2201104	8/27/2024	9:02 AM	240	8500	7700	NA	7760	2940	546	9.5
6	Ellingson "A"	2300312	8/27/2024	10:10 AM	110	4250	3600	0.02	3410	1250	23	8.2
7	Goeddertz	2300367	8/27/2024	11:32 AM	56	5000	4300	NA	4590	1640	583	8.9
8	Leach	2201101	8/27/2024	11:58 AM	56	6500	5500	NA	6210	2040	1710	8.8
9	Page 56	2300132	8/27/2024	12:22 PM	25	4900	4250	NA	4310	1580	635	9.4
10	Swayze	2201113	8/27/2024	9:38 AM	33	4700	4500	0.03	3960	1440	5	7.4
11												

Privilege and License Tax Rate Discussion

Attached you will find data and information regarding price forecasts and budgeting information in relation to the privilege and license tax rate. The first spreadsheet is the most important one, but the following sheets provide an overview of the steps used to generate the forecast and a helpful graph that breaks down the rate needed to meet Board operating expenditures at a given oil price. We are currently in the row on each spreadsheet that has a background color of orange. Numbers in red represent forecasts and those in black are either fixed or based upon prior forecasts. Since income and expenditures are updated to actual numbers when they become available only the row with the orange background and rows below it are important at this time.

The assumptions for the forecast are:

- Tax rate of 0.22%, or the current rate.
- An average oil price of $55/barrel was used for FY26 and a constant oil price of $50/barrel for FY27. EIA's WTI forecast for this period is an average of $62/barrel for FY26 and $55/barrel for FY27. A 0.88 differential was used to come up with the prices for Montana.
- Oil production for FY26 is expected to decline based on lower oil price and an anticipated drop in completions. The decline is forecasted to slow for FY27 through anticipated completions if price remains stable. Production declines quickly when wells are not being completed, but can be maintained with a hand full of Bakken completions.
- Expenditures shown for the remainder of the biennium are the budgeted expenditures. Actual expenditures have been 15-20% below budget.
- In addition to the tax on oil and gas production we also have annual injection well fees and a federal UIC grant, which are assumed constant.

Revenue through the past biennium has exceeded expenditures, and the reserve account balance grew from approximately $7 million to nearly $11 million at the end of FY 2025.

Using the production volumes, price, and budgeted expenditures as outlined above, a tax rate of nearly 0.3% would be needed to meet Board operations plus non-Board expenditures. However, with such a high reserve account to work with, the Board should still consider a tax rate reduction to take advantage of the statutory changes from SB 339.

Rulemaking to lower the tax rate would take 6-12 months and it is estimated that the new rate would take effect around the second quarter of FY 2027 (October 1, 2026). Lowering the tax rate from 0.22% to 0.18% within this timeframe and using the assumptions from above, the total expenditures for the FY 26/27 biennium would be approximately $7.7 million, total income would be approximately $6.6 million, and the account balance at the end of the biennium (June 30, 2027) is estimated to be $9.8 million. This would allow an estimated $320,000 to be deposited into the Damage Mitigation Account.

Note: High special revenue accounts may be the target of 'legislative appropriation' during the next session.

Recommendation: Initiate rulemaking to reduce P&L tax rate to 0.18%.

Overview

6/4/2025								
							Special Revenue Account	
Month	Months	CY	FY	Prod Receipt	Expenditures	Revenue	Beginning	End
23	Jul-Sep	3Q-2020	FY 21 Q1	CY 1Q-2020	$ 729,839	$ 583,748	$ 4,597,646	$ 4,451,555
24	Oct-Dec	4Q-2020	FY 21 Q2	CY 2Q-2020	$ 541,975	$ 226,365	$ 4,451,555	$ 4,135,945
25	Jan-Mar	1Q-2021	FY 21 Q3	CY 3Q-2020	$ 788,240	$ 667,034	$ 4,135,945	$ 4,014,739
26	Apr-Jun	2Q-2021	FY 21 Q4	CY 4Q-2020	$ 567,921	$ 543,042	$ 4,014,739	$ 3,989,860
27	Jul-Sep	3Q-2021	FY 22 Q1	CY 1Q-2021	$ 953,884	$ 703,003	$ 3,989,860	$ 3,738,979
28	Oct-Dec	4Q-2021	FY 22 Q2	CY 2Q-2021	$ 571,559	$ 764,254	$ 3,738,979	$ 3,931,674
29	Jan-Mar	1Q-2022	FY 22 Q3	CY 3Q-2021	$ 700,429	$ 1,056,365	$ 3,931,674	$ 4,287,610
30	Apr-Jun	2Q-2022	FY 22 Q4	CY 4Q-2021	$ 728,937	$ 1,036,084	$ 4,287,610	$ 4,594,758
31	Jul-Sep	3Q-2022	FY 23 Q1	CY 1Q-2022	$ 825,509	$ 1,138,805	$ 4,594,758	$ 4,908,054
32	Oct-Dec	4Q-2022	FY 23 Q2	CY 2Q-2022	$ 894,784	$ 1,592,452	$ 4,908,054	$ 5,605,722
33	Jan-Mar	1Q-2023	FY 23 Q3	CY 3Q-2022	$ 567,217	$ 1,596,006	$ 5,605,722	$ 6,634,510
34	Apr-Jun	2Q-2023	FY 23 Q4	CY 4Q-2022	$ 1,006,562	$ 1,254,739	$ 6,634,510	$ 6,882,688
35	Jul-Sep	3Q-2023	FY 24 Q1	CY 1Q-2023	$ 719,423	$ 1,169,739	$ 6,882,688	$ 7,333,003
36	Oct-Dec	4Q-2023	FY 24 Q2	CY 2Q-2023	$ 585,184	$ 1,098,417	$ 7,333,003	$ 7,846,236
37	Jan-Mar	1Q-2024	FY 24 Q3	CY 3Q-2023	$ 572,689	$ 1,461,370	$ 7,846,236	$ 8,734,917
38	Apr-Jun	2Q-2024	FY 24 Q4	CY 4Q-2023	$ 762,932	$ 1,425,009	$ 8,734,917	$ 9,396,994
39	Jul-Sep	3Q-2024	FY 25 Q1	CY 1Q-2024	$ 777,318	$ 1,170,653	$ 9,396,994	$ 9,790,330
40	Oct-Dec	4Q-2024	FY 25 Q2	CY 2Q-2024	$ 668,964	$ 1,245,585	$ 9,790,330	$ 10,366,950
41	Jan-Mar	1Q-2025	FY 25 Q3	CY 3Q-2024	$ 947,556	$ 1,366,665	$ 10,366,950	$ 10,786,060
42	Apr-Jun	2Q-2025	FY 25 Q4	CY 4Q-2024	$ 1,134,024	$ 1,269,447	$ 10,786,060	$ 10,921,483
43	Jul-Sep	3Q-2025	FY 26 Q1	CY 1Q-2025	$ 1,180,824	$ 1,073,844	$ 10,921,483	$ 10,814,502
44	Oct-Dec	4Q-2025	FY 26 Q2	CY 2Q-2025	$ 880,824	$ 863,119	$ 10,814,502	$ 10,796,798
45	Jan-Mar	1Q-2026	FY 26 Q3	CY 3Q-2025	$ 880,824	$ 1,001,041	$ 10,796,798	$ 10,917,015
46	Apr-Jun	2Q-2026	FY 26 Q4	CY 4Q-2025	$ 880,824	$ 828,712	$ 10,917,015	$ 10,864,903
47	Jul-Sep	3Q-2026	FY 27 Q1	CY 1Q-2026	$ 1,197,073	$ 751,253	$ 10,864,903	$ 10,419,083
48	Oct-Dec	4Q-2026	FY 27 Q2	CY 2Q-2026	$ 897,073	$ 608,647	$ 10,419,083	$ 10,130,657
49	Jan-Mar	1Q-2027	FY 27 Q3	CY 3Q-2026	$ 897,073	$ 793,490	$ 10,130,657	$ 10,027,073
50	Apr-Jun	2Q-2027	FY 27 Q4	CY 4Q-2026	$ 897,073	$ 643,764	$ 10,027,073	$ 9,773,765
FY26/27					$ 7,711,587	$ 6,563,869	$ 10,921,483	$ 9,773,765

Prices and Production

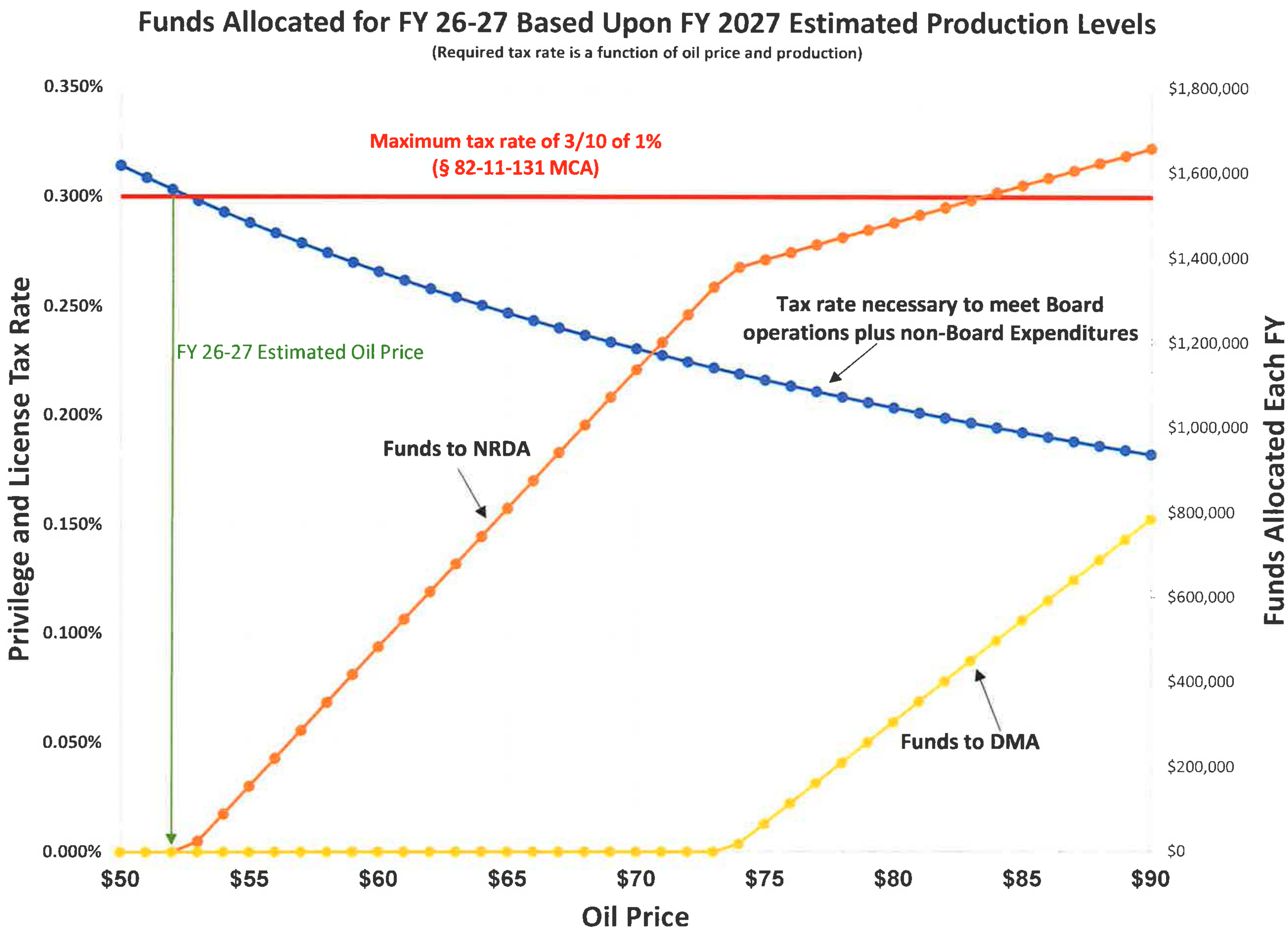
UPDATE	6/4/2025													
Month	**Months**	**CY**	**FY**	Production Period	DOR Oil	DOR Gas	HJ0002 MT price	EIA -Oil WTI	EIA- Oil W/0.88 Diff	Used	Oil (Bbls)	Gas (mcf)		Actual or Foecast
23	Jul-Sep	3Q-2020	FY 21 Q1	CY 1Q-2020	$ 39.17	$ 1.09	$ 38.66	$ 54.60	$ 48.05		5,581,910	9,712,876	5,581,910	actual
24	Oct-Dec	4Q-2020	FY 21 Q2	CY 2Q-2020	$ 20.39	$ 0.67	$ 38.66	$ 54.60	$ 48.05		4,121,065	8,076,457	4,121,065	actual
25	Jan-Mar	1Q-2021	FY 21 Q3	CY 3Q-2020	$ 34.85	$ 1.15	$ 52.18	$ 58.09	$ 51.12		482,134	9,055,340	482,134	actual
26	Apr-Jun	2Q-2021	FY 21 Q4	CY 4Q-2020	$ 36.57	$ 1.71	$ 52.18	$ 66.19	$ 58.25		4,583,861	9,003,995	4,583,861	actual
27	Jul-Sep	3Q-2021	FY 22 Q1	CY 1Q-2021	$ 52.18	$ 3.79	$ 52.18	$ 70.61	$ 62.14		4,767,483	8,702,747	4,767,483	actual
28	Oct-Dec	4Q-2021	FY 22 Q2	CY 2Q-2021	$ 61.22	$ 2.24	$ 52.18	$ 77.27	$ 68.00		4,619,411	8,776,172	4,619,411	actual
29	Jan-Mar	1Q-2022	FY 22 Q3	CY 3Q-2021	$ 65.90	$ 3.53	$ 91.66	$ 95.18	$ 83.76		4,729,785	9,406,577	4,729,785	actual
30	Apr-Jun	2Q-2022	FY 22 Q4	CY 4Q-2021	$ 73.07	$ 4.62	$ 91.66	$ 108.72	$ 95.67		4,756,354	9,329,143	4,756,354	actual
31	Jul-Sep	3Q-2022	FY 23 Q1	CY 1Q-2022	$ 90.37	$ 4.86	$ 91.66	$ 93.18	$ 82.00		4,777,733	8,906,770	4,777,733	actual
32	Oct-Dec	4Q-2022	FY 23 Q2	CY 2Q-2022	$ 106.24	$ 6.45	$ 91.66	$ 82.79	$ 72.86		5,170,664	8,960,792	5,170,664	actual
33	Jan-Mar	1Q-2023	FY 23 Q3	CY 3Q-2022	$ 89.54	$ 4.86	$ 77.78	$ 76.08	$ 66.95		5,530,676	9,973,805	5,530,676	actual
34	Apr-Jun	2Q-2023	FY 23 Q4	CY 4Q-2022	$ 80.79	$ 4.35	$ 77.78	$ 73.76	$ 64.91		5,052,595	9,385,653	5,052,595	actual
35	Jul-Sep	3Q-2023	FY 24 Q1	CY 1Q-2023	$ 71.87	$ 5.32	$ 77.78	$ 74.43	$ 65.50		5,744,199	9,466,509	5,744,199	actual
36	Oct-Dec	4Q-2023	FY 24 Q2	CY 2Q-2023	$ 70.82	$ 2.03	$ 77.78	$ 74.43	$ 65.50		5,564,961	9,579,166	5,564,961	actual
37	Jan-Mar	1Q-2024	FY 24 Q3	CY 3Q-2023	$ 78.98	$ 2.36	$ 78.08	$ 77.50	$ 68.20		5,596,274	9,933,756	5,596,274	actual
38	Apr-Jun	2Q-2024	FY 24 Q4	CY 4Q-2023	$ 74.49	$ 2.38	$ 78.08	$ 81.77	$ 71.96		5,806,657	9,551,587	5,806,657	actual
39	Jul-Sep	3Q-2024	FY 25 Q1	CY 1Q-2024	$ 71.95	$ 3.18	$ 78.08	$ 77.50	$ 68.20		5,866,665	9,764,482	5,866,665	actual
40	Oct-Dec	4Q-2024	FY 25 Q2	CY 2Q-2024	$ 75.58	$ 2.39	$ 78.08	$ 81.77	$ 71.96		6,624,257	9,641,893	6,624,257	actual
41	Jan-Mar	1Q-2025	FY 25 Q3	CY 3Q-2024	$ 70.39	$ 2.47	$ 79.82	$ 76.43	$ 67.26		6,728,916	9,253,815	6,728,916	actual
42	Apr-Jun	2Q-2025	FY 25 Q4	CY 4Q-2024			$ 79.82	$ 70.74	$ 62.25	$ 62.29	7,349,341	9,123,912	7,349,341	actual
43	Jul-Sep	3Q-2025	FY 26 Q1	CY 1Q-2025			$ 66.00	$ 71.85	$ 63.23	$ 63.23	6,518,057	9,123,912	6,518,057	forecast
44	Oct-Dec	4Q-2025	FY 26 Q2	CY 2Q-2025			$ 66.00	$ 60.85	$ 53.55	$ 53.55	5,969,772	9,123,912	5,969,772	forecast
45	Jan-Mar	1Q-2026	FY 26 Q3	CY 3Q-2025			$ 66.00	$ 58.00	$ 51.04	$ 51.04	5,682,884	9,123,912	5,682,884	forecast
46	Apr-Jun	2Q-2026	FY 26 Q4	CY 4Q-2025			$ 66.00	$ 57.00	$ 50.16	$ 50.16	5,425,920	9,123,912	5,425,920	forecast
47	Jul-Sep	3Q-2026	FY 27 Q1	CY 1Q-2026			$ 71.83	$ 56.00	$ 49.28	$ 50.00	5,193,743	9,123,912	5,309,832	forecast
48	Oct-Dec	4Q-2026	FY 27 Q2	CY 2Q-2026			$ 71.83	$ 56.00	$ 49.28	$ 50.00	4,982,349	9,123,912	5,088,046	forecast
49	Jan-Mar	1Q-2027	FY 27 Q3	CY 3Q-2026			$ 71.83	$ 55.00	$ 48.40	$ 50.00	4,788,583	9,123,912	4,885,466	forecast
50	Apr-Jun	2Q-2027	FY 27 Q4	CY 4Q-2026			$ 71.83	$ 54.00	$ 47.52	$ 50.00	4,609,945	9,123,912	4,699,264	forecast

Oil and Gas Tax Receipts

Month	Months	CY	FY	Prod Receipt	Oil Prod	Gas Prod	Oil $	Gas $	Tax	Oil Value	Gas Value	P & L Income
6/4/2025												
23	Jul-Sep	3Q-2020	FY 21 Q1	CY 1Q-2020	5,581,910	9,712,876	$ 39.17	$ 1.09	0.0025	$ 546,609	$ 26,468	$ 573,076
24	Oct-Dec	4Q-2020	FY 21 Q2	CY 2Q-2020	4,121,065	8,076,457	$ 20.39	$ 0.67	0.0025	$ 210,071	$ 13,528	$ 223,599
25	Jan-Mar	1Q-2021	FY 21 Q3	CY 3Q-2020	482,134	9,055,340	$ 34.85	$ 1.15	0.0025	$ 42,006	$ 26,034	$ 68,040
26	Apr-Jun	2Q-2021	FY 21 Q4	CY 4Q-2020	4,583,861	9,003,995	$ 36.57	$ 1.71	0.0025	$ 419,079	$ 38,492	$ 457,572
27	Jul-Sep	3Q-2021	FY 22 Q1	CY 1Q-2021	4,767,483	8,702,747	$ 52.18	$ 3.79	0.0025	$ 621,918	$ 82,459	$ 704,377
28	Oct-Dec	4Q-2021	FY 22 Q2	CY 2Q-2021	4,619,411	8,776,172	$ 61.22	$ 2.24	0.0025	$ 707,001	$ 49,147	$ 756,147
29	Jan-Mar	1Q-2022	FY 22 Q3	CY 3Q-2021	4,729,785	9,406,577	$ 65.90	$ 3.53	0.0025	$ 779,232	$ 83,013	$ 862,245
30	Apr-Jun	2Q-2022	FY 22 Q4	CY 4Q-2021	4,756,354	9,329,143	$ 73.07	$ 4.62	0.0025	$ 868,867	$ 107,752	$ 976,619
31	Jul-Sep	3Q-2022	FY 23 Q1	CY 1Q-2022	4,777,733	8,906,770	$ 90.37	***$ 4.86***	0.0025	$ 1,079,409	$ 108,217	$ 1,187,627
32	Oct-Dec	4Q-2022	FY 23 Q2	CY 2Q-2022	5,170,664	8,960,792	$ 106.24	***$ 6.45***	0.0025	$ 1,373,328	$ 144,493	$ 1,517,821
33	Jan-Mar	1Q-2023	FY 23 Q3	CY 3Q-2022	5,530,676	9,973,805	$ 89.54	***$ 4.86***	0.0025	$ 1,238,042	$ 121,182	$ 1,359,224
34	Apr-Jun	2Q-2023	FY 23 Q4	CY 4Q-2022	5,052,595	9,385,653	***$ 80.79***	***$ 4.35***	0.0025	$ 1,020,498	$ 102,069	$ 1,122,567
35	Jul-Sep	3Q-2023	FY 24 Q1	CY 1Q-2023	5,744,199	9,466,509	***$ 71.87***	***$ 5.32***	0.0025	$ 1,032,089	$ 125,905	$ 1,157,994
36	Oct-Dec	4Q-2023	FY 24 Q2	CY 2Q-2023	5,564,961	9,579,166	***$ 70.82***	***$ 2.03***	0.0025	$ 985,276	$ 48,614	$ 1,033,891
37	Jan-Mar	1Q-2024	FY 24 Q3	CY 3Q-2023	5,596,274	9,933,756	***$ 78.98***	***$ 2.36***	0.0025	$ 1,104,984	$ 58,609	$ 1,163,593
38	Apr-Jun	2Q-2024	FY 24 Q4	CY 4Q-2023	5,806,657	9,551,587	***$ 74.49***	***$ 2.38***	0.0025	$ 1,081,345	$ 56,832	$ 1,138,177
39	Jul-Sep	3Q-2024	FY 25 Q1	CY 1Q-2024	5,866,665	9,764,482	***$ 71.95***	***$ 3.18***	0.0025	$ 1,055,266	$ 77,628	$ 1,132,894
40	Oct-Dec	4Q-2024	FY 25 Q2	CY 2Q-2024	6,624,257	9,641,893	***$ 75.58***	***$ 2.39***	0.0022	$ 1,101,455	$ 50,697	$ 1,152,152
41	Jan-Mar	1Q-2025	FY 25 Q3	CY 3Q-2024	6,728,916	9,253,815	***$ 70.39***	***$ 2.70***	0.0022	$ 1,009,158	$ 47,884	$ 1,057,041
42	Apr-Jun	2Q-2025	FY 25 Q4	CY 4Q-2024	7,349,341	9,123,912	***$ 62.29***	***$ 2.70***	0.0022	$ 1,007,139	$ 54,196	$ 1,061,335
43	Jul-Sep	3Q-2025	FY 26 Q1	CY 1Q-2025	6,518,057	9,123,912	***$ 63.23***	***$ 2.50***	0.0022	$ 906,672	$ 50,182	$ 956,854
44	Oct-Dec	4Q-2025	FY 26 Q2	CY 2Q-2025	5,969,772	9,123,912	***$ 53.55***	***$ 2.50***	0.0022	$ 703,273	$ 50,182	$ 753,454
45	Jan-Mar	1Q-2026	FY 26 Q3	CY 3Q-2025	5,682,884	9,123,912	***$ 51.04***	***$ 2.50***	0.0022	$ 638,120	$ 50,182	$ 688,301
46	Apr-Jun	2Q-2026	FY 26 Q4	CY 4Q-2025	5,425,920	9,123,912	***$ 50.16***	***$ 2.50***	0.0022	$ 598,761	$ 50,182	$ 648,943
47	Jul-Sep	3Q-2026	FY 27 Q1	CY 1Q-2026	5,309,832	9,123,912	***$ 50.00***	***$ 2.50***	0.0022	$ 584,081	$ 50,182	$ 634,263
48	Oct-Dec	4Q-2026	FY 27 Q2	CY 2Q-2026	5,088,046	9,123,912	***$ 50.00***	***$ 2.50***	0.0018	$ 457,924	$ 41,058	$ 498,982
49	Jan-Mar	1Q-2027	FY 27 Q3	CY 3Q-2026	4,885,466	9,123,912	***$ 50.00***	***$ 2.50***	0.0018	$ 439,692	$ 41,058	$ 480,750
50	Apr-Jun	2Q-2027	FY 27 Q4	CY 4Q-2026	4,699,264	9,123,912	***$ 50.00***	***$ 2.50***	0.0018	$ 422,934	$ 41,058	$ 463,991
			FY 24/25		49,281,270	76,315,120				$ 8,376,712	$ 520,365	$ 8,897,077
			FY 26/27		43,579,241	72,991,296				$ 4,751,457	$ 374,080	$ 5,125,537

Expenditures

6/2/2025							
Month	Months	CY	FY	Disbursements Total	BOGC Budgeted	BOGC Expended	Transfers Total
23	Jul-Sep	3Q-2020	FY 21 Q1	729,839.12	530,636.25	340,202.55	381,834.57
24	Oct-Dec	4Q-2020	FY 21 Q2	541,975.12	530,636.25	381,497.56	160,477.56
25	Jan-Mar	1Q-2021	FY 21 Q3	788,240.02	530,636.25	401,247.68	211,928.34
26	Apr-Jun	2Q-2021	FY 21 Q4	567,920.97	530,636.25	501,656.65	66,063.14
27	Jul-Sep	3Q-2021	FY 22 Q1	953,884.33	516,222.50	553,124.06	388,421.27
28	Oct-Dec	4Q-2021	FY 22 Q2	571,559.11	516,222.50	141,772.00	298,245.11
29	Jan-Mar	1Q-2022	FY 22 Q3	700,428.53	516,222.50	412,684.00	233,759.53
30	Apr-Jun	2Q-2022	FY 22 Q4	728,936.56	516,222.50	535,673.20	188,298.15
31	Jul-Sep	3Q-2022	FY 23 Q1	825,508.75	518,635.00	333,817.58	406,968.07
32	Oct-Dec	4Q-2022	FY 23 Q2	894,784.33	518,635.00	589,417.03	207,602.62
33	Jan-Mar	1Q-2023	FY 23 Q3	567,216.92	518,635.00	371,451.94	180,890.98
34	Apr-Jun	2Q-2023	FY 23 Q4	1,006,561.56	518,635.00	404,935.84	225,816.83
35	Jul-Sep	3Q-2023	FY 24 Q1	719,423.45	563,942.50	311,809.00	407,614.45
36	Oct-Dec	4Q-2023	FY 24 Q2	585,184.17	563,942.50	400,234.70	184,949.47
37	Jan-Mar	1Q-2024	FY 24 Q3	572,688.80	563,942.50	457,043.15	115,645.65
38	Apr-Jun	2Q-2024	FY 24 Q4	762,931.79	563,942.50	409,096.30	139,570.13
39	Jul-Sep	3Q-2024	FY 25 Q1	777,317.81	377,698.45	377,698.45	399,619.36
40	Oct-Dec	4Q-2024	FY 25 Q2	668,963.97	657,385.85	514,292.24	150,895.73
41	Jan-Mar	1Q-2025	FY 25 Q3	947,555.75	657,385.85	657,385.85	109,686.06
42	Apr-Jun	2Q-2025	FY 25 Q4	1,134,023.86	657,385.85	657,385.85	429,150.85
43	Jul-Sep	3Q-2025	FY 26 Q1	1,180,823.75	599,034.00	599,034.00	515,966.00
44	Oct-Dec	4Q-2025	FY 26 Q2	880,823.75	599,034.00	599,034.00	215,966.00
45	Jan-Mar	1Q-2026	FY 26 Q3	880,823.75	599,034.00	599,034.00	215,966.00
46	Apr-Jun	2Q-2026	FY 26 Q4	880,823.75	599,034.00	599,034.00	215,966.00
47	Jul-Sep	3Q-2026	FY 27 Q1	1,197,073.00	614,802.50	614,802.50	516,367.00
48	Oct-Dec	4Q-2026	FY 27 Q2	897,073.00	614,802.50	614,802.50	216,367.00
49	Jan-Mar	1Q-2027	FY 27 Q3	897,073.00	614,802.50	614,802.50	216,367.00
50	Apr-Jun	2Q-2027	FY 27 Q4	897,073.00	614,802.50	614,802.50	216,367.00
			FY 24/25	$ 6,168,090	$ 4,605,626	$ 3,784,946	$ 1,937,132
			FY 26/27	$ 7,711,587	$ 4,855,346	$ 4,855,346	$ 2,329,332



Funds Allocated for FY 26-27 Based Upon FY 2027 Estimated Production Levels
(Required tax rate is a function of oil price and production)
Maximum tax rate of 3/10 of 1%
(§ 82-11-131 MCA)
FY 26-27 Estimated Oil Price
Tax rate necessary to meet Board operations plus non-Board Expenditures
Funds to NRDA
Funds to DMA
Privilege and License Tax Rate
0.350%
0.300%
0.250%
0.200%
0.150%
0.100%
0.050%
0.000%
Funds Allocated Each FY
$1,800,000
$1,600,000
$1,400,000
$1,200,000
$1,000,000
$800,000
$600,000
$400,000
$200,000
$0
$50
$55
$60
$65
$70
$75
$80
$85
$90
Oil Price

EXHIBIT 7
June 11, 2025

Phoenix Operating LLC

UIC Permit Violations

1. Injecting into the Ronin 1 SWD prior to submitting the Dakota water analysis as required by the conditions of approval (COA) on the sundry notice and receiving authorization to inject. (Phoenix began injecting 4/12/2025 and BOGC received the water analysis 4/14/2025 after having asked for it).

2. Setting the packer in the Ronin 1 SWD 131 ft. above the top of the injection perforations without approval when the COA on the sundry notice required the packer to be set within 100 ft. of the top injection perforations.

3. The surface location of the Samurai SWD was moved without approval, this affects the area of review for the UIC permit and is also a violation of the drilling permit. (Well Spudded 4/29/2025).

4. The Samurai SWD was not constructed to allow the packer to be within 100 ft. of the top perforations as required in the COA on the sundry notice.

EXHIBIT 8

MONTANA BOARD OF OIL AND GAS CONSERVATION
FINANCIAL STATEMENT
As of 6/6/2025
Fiscal Year 2025: Percent of Year Elapsed - 93%

		Budget	Expends	%	Remaining
Regulatory	Personal Services	1,376,382	1,074,653	78	301,729
UIC	Personal Services	349,503	289,941	83	59,562
	Total	**1,725,885**	**1,364,594**	**79**	**361,291**
Regulatory	Equipment & Assets	73,800	-	-	73,800
UIC	Equipment & Assets	16,200	-	-	16,200
	Total	**90,000**	**-**	**-**	**90,000**
Regulatory	Operating Expenses:				
	Contracted Services	172,366	53,711	31	118,655
	Supplies & Materials	57,042	39,724	70	17,318
	Communication	50,495	44,595	88	5,900
	Travel	20,752	12,405	60	8,347
	Rent	1,354	884	65	470
	Utilities	23,778	12,546	53	11,232
	Repair/Maintenance	61,081	60,407	99	674
	Other Expenses	36,118	17,619	49	18,499
	Total Operating Expenses	422,986	241,892	57	181,094
UIC	Operating Expenses:				
	Contracted Services	37,481	10,711	29	26,770
	Supplies & Materials	12,521	8,047	64	4,474
	Communication	11,084	8,225	74	2,859
	Travel	4,555	7,930	174	(3,375)
	Rent	297	194	65	103
	Utilities	5,219	2,773	53	2,446
	Repair/Maintenance	13,408	12,197	91	1,211
	Other Expenses	7,929	8,773	111	(844)
	Total Operating Expenses	92,494	58,850	64	33,644
	Total	**515,480**	**300,742**	**58**	**214,738**
Regulatory	Debt Services	15,163	15,392	102	(229)
UIC	Debt Services	3,328	3,379	102	(51)
	Total	**18,491**	**18,771**	**102**	**(280)**

	Budget	Expends	%	Remaining
Carryforward FY23				
Personal Services	45,269	-	0	45,269
Operating Expenses	45,269	-	0	45,269
Equipment & Assests	45,269	-	0	45,269
Total	**135,807**	**-**	**0**	**135,807**

Funding Breakout	**2025 Total Budget**	**2025 Total Expends**	**%**
State Special	**2,349,856**	**1,684,107**	**72**
Federal 2024 UIC (10-1-2023 to 9-30-2024)	**133,000**	**132,999**	**100**
Federal 2025 UIC (10-1-2024 to 9-30-2025)	**133,000**	**-**	**0**
Total	**2,615,856**	**1,817,107**	**69**

REVENUE INTO STATE SPECIAL REVENUE ACCOUNT		
	FY 25	FY 24
Oil & Gas Production Tax	$ 2,133,705	$ 4,428,833
Oil Production Tax	2,027,358	4,197,030
Gas Production Tax	106,347	231,803
Drilling Permit Fees	15,175	16,250
UIC Permit Fees	226,030	235,800
Interest on Investments	417,921	354,719
Copies of Documents	(360)	323
Miscellaneous Reimbursements	14,974	48,483
TOTAL	$ 2,807,444	$ 5,084,408
Account Balance	**$ 11,149,406**	

REVENUE INTO DAMAGE MITIGATION ACCOUNT		
	FY 25	FY 24
RIT Investment Earnings:	-	400,935
July	-	-
August	-	39,095
September	-	26,736
October	-	33,325
November	-	33,864
December	-	28,116
January	-	40,140
February	-	34,541
March	-	35,353
April	-	28,579
May	-	37,618
June	-	63,569
Bond Forfeitures:	228,388	20,019
Interest on Investments	47,413	30,448
TOTAL	$ 275,801	$ 451,402
Account Balance	**$ 1,219,999**	

REVENUE INTO GENERAL FUND FROM FINES		
		FY 25
GRASSY BUTTE LLC	8/2/2024	120
NOAH ENERGY INC	8/9/2024	650
JUSTICE SWD LLC	8/16/2024	120
COOL SPRING COLONY INC	8/23/2024	130
BLACK GOLD ENERGY	9/13/2024	70
BLACK GOLD ENERGY	9/13/2024	70
UNITED STATES ENERGY CORP	9/13/2024	60
CONTANGO RESOURCES	9/17/2024	4,000
RIMROCK COLONY	9/17/2024	130
JUSTICE SWD LLC	9/27/2024	1,000
D&A WATER DISPOSAL LLC	10/11/2024	160
BALLANTYNE VENTURES LLC	10/16/2024	90
MONTANA ENERGY COMPANY LLC	11/8/2024	2,500
RELENTLESS OILFIELD INNOVATION LLC	11/22/2024	140
PAUGH THEA OR JERRY	1/24/2025	80
YELLOWSTONE PETROLEUMS INC	2/12/2025	150
COMANCHE DRILLING LLC	2/14/2025	200
BUCKLEY PRODUCING CO	2/21/2025	140
HAWLEY OIL LLP	2/28/2025	250
WADMAN VALERIE	3/28/2025	160
S&L ENERGY INC	**4/18/2025**	**70**
SAGE CREEK COLONY	**5/16/2025**	**340**
RANCK OIL COMPANY INC	**5/23/2025**	**2,480**
DIAMOND HALO GROUP LLC	**6/2/2025**	**160**
TOTAL		$ 13,270

FEDERAL ORPHAN WELL PLUGGING CONTRACTS					
Name	*Authorized Amt*	*Expended*	*Balance*	*Status*	*Expiration Date*
PLENTYWOOD PLUG AND RECLAIM WELLS	$ 3,547,496	$ 3,317,379	$ 230,118	Under Contract	9/30/2025
ROUNDUP B PLUG AND RECLAIM WELL	157,992	-	157,992	Under Contract	9/30/2025
SHELBY 2 PLUG AND RECLAIM WELLS	610,693	505,864	104,830	Under Contract	9/30/2025
SHELBY 3 PLUG AND RECLAIM WELLS	363,788	-	363,788	Under Contract	9/30/2025
SHELBY 4 PLUG AND RECLAIM WELLS	250,800	-	250,800	Under Contract	9/30/2025
SHELBY H2S PLUG AND RECLAIM WELLS	218,430	-	218,430	Under Contract	9/30/2025
PLENTYWOOD WEST PLUG AND RECLAIM WELLS	1,079,997	218,000	861,997	Under Contract	9/30/2025
~~PLENTYWOOD WEST PLUG AND RECLAIM WELLS~~	~~1,602,967~~		~~1,602,967~~	~~Bond Forfeited~~	~~9/30/2025~~
ROUNDUP A PLUG AND RECLAIM WELL	3,579,402	3,498,162	81,241	Completed	9/30/2025
SIDNEY PLUG AND RECLAIM WELLS	1,804,940	1,804,940	-	Completed	9/30/2025
GLENDIVE DISTRICT PLUG AND RECLAIM WELLS	791,250	791,250	-	Completed	9/30/2025
SHELBY 1 PLUG AND RECLAIM WELLS	676,361	607,140	69,221	Completed	9/30/2025
ROUNDUP C PLUG AND RECLAIM WELLS	289,530	238,464	51,066	Completed	9/30/2025
CBM PLUG AND RECLAIM WELLS	281,300	230,700	50,600	Completed	9/30/2025
MURRAY 1 PLUG AND RECLAIM WELL	266,620	222,183	44,437	Completed	9/30/2025
TURNER 13-22 AND TORDALE 42-21 PLUG AND RECLAIM WELLS	133,503	111,253	22,251	Completed	9/30/2025
HANNAH 5 PLUG AND RECLAIM WELL	47,113	47,113	-	Completed	9/30/2025
STATE 8-8 PLUG AND RECLAIM WELL	44,965	44,965	-	Completed	9/30/2025
TOI AG STATION RECLAMATION	26,232	26,232	-	Completed	9/30/2023
TOTAL	**$ 15,773,378**	**$ 11,663,643**	**$ 4,109,735**		

OPERATING CONTRACTS					
Name	*Authorized Amt*	*Expended*	*Balance*	*Status*	*Expiration Date*
Empire Roofing Inc - Install Snow Guards	**$ 3,742.00**	**$ -**	**$ 3,742.00**	**Under Contract**	**6/30/2025**
Savage Public Schools Petroleum Resources Workshop	**15,000**	**-**	**15,000**	**Under Contract**	**7/31/2025**
Model Year 2025 Light Duty Trucks (4)	**187,316**	**-**	**187,316**	**Under Contract**	**8/15/2025**
Agency Legal Services 2025	70,000	14,759.58	55,240	Under Contract	6/30/2025
Billings Janitorial	21,110	17,537	3,573	Under Contract	9/30/2025
Billings Lawn and Snow Removal	48,000	38,290	9,710	Under Contract	9/30/2025
Shelby O&G Lease	110,946	109,405	1,541	Under Contract	5/31/2025
LED Lighting Upgrade Project	33,990	33,990	-	Completed	6/30/2025
TOTAL	**$ 456,114**	**$ 179,992**	**$ 276,122**		

Agency Legal Services Expenditure Breakout	
Case	Amt Spent
BOGC Duties	$ 14,251
D&A	$ 508
Total	**$ 14,760**

CONTRACTS WAITING TO BE FINALIZED		
Name	*Authorized Amt*	*Expiration Date*
Bootstrap Plug and Reclaim 3 wells	$ 713,685	11/30/2025
Americlean - carpet cleaning	$ 1,353	5/1/2026

EXHIBIT 9

Montana Board of Oil and Gas Conservation
Summary of Bond Activity

4/10/2025 Through 6/10/2025

Approved

Coyote Resources LLC Houston TX		952 T1	Approved Amount: Purpose:	5/21/2025 $1,500.00 UIC Single Well Bond
Surety Bond	$1,500.00	Pennsylvania Insurance Company		ACT
Gallup City Oil, LLC Conrad MT		674 G1	Approved Amount: Purpose:	5/21/2025 $1,500.00 Single Well Bond
Certificate of Deposit	$1,500.00	FIRST BANK MONTANA, N. A.		ACT
Hereford Resources, LLC Chester MT		941 G6	Approved Amount: Purpose:	5/19/2025 $10,000.00 Single Well Bond
Certificate of Deposit	$10,000.00	GLACIER BANK FSB		ACT
Hereford Resources, LLC Chester MT		941 G5	Approved Amount: Purpose:	5/5/2025 $10,000.00 Single Well Bond
Certificate of Deposit	$10,000.00	GLACIER BANK FSB		ACT
M-Tex Oil, LLC Williston ND		956 G1	Approved Amount: Purpose:	6/6/2025 $10,000.00 Single Well Bond
Certificate of Deposit	$10,000.00	Stockman Bank of Montana		ACT
M-Tex Oil, LLC Williston ND		956 G2	Approved Amount: Purpose:	6/6/2025 $10,000.00 Single Well Bond
Certificate of Deposit	$10,000.00	Stockman Bank of Montana		ACT
Phoenix Operating LLC Denver CO		935 T2	Approved Amount: Purpose:	4/24/2025 $10,000.00 UIC Single Well Bond
Surety Bond	$10,000.00	U.S. Specialty Insurance Co.		ACT
Ridge Oil & Gas, LLC Plano TX		913 M3	Approved Amount: Purpose:	4/16/2025 $250,000.00 Multiple Well Bond
Surety Bond	$250,000.00	U.S. Specialty Insurance Co.		ACT
Sun Coulee, LLC Martinsdale MT		915 T3	Approved Amount: Purpose:	6/5/2025 $10,000.00 UIC Single Well Bond
Certificate of Deposit	$10,000.00	Stockman Bank of Montana		ACT
Sun Coulee, LLC Martinsdale MT		915 T2	Approved Amount: Purpose:	6/5/2025 $10,000.00 UIC Single Well Bond
Certificate of Deposit	$10,000.00	Stockman Bank of Montana		ACT

Montana Board of Oil and Gas Conservation
Summary of Bond Activity

4/10/2025 Through 6/10/2025

Approved

Sun Coulee, LLC Martinsdale MT		915 T1	Approved Amount: Purpose:	6/5/2025 $10,000.00 UIC Single Well Bond
Certificate of Deposit	$10,000.00	Stockman Bank of Montana		ACT
White Rock Oil & Gas, LLC Plano TX		779 T13	Approved Amount: Purpose:	4/25/2025 $10,000.00 UIC Single Well Bond
Surety Bond	$10,000.00	UNITED STATES FIRE INS. CO.		ACT

Canceled

Decker Operating Company, L.L.C. Houston TX	233 M1	Canceled Amount: Purpose:	5/5/2025 $50,000.00 Multiple Well Bond
Global Helium (USA) Corp. Calgary AB	917 G1	Canceled Amount: Purpose:	5/6/2025 $10,000.00 Single Well Bond
Lustre Oil Company LLC Winnett MT	898 G3	Canceled Amount: Purpose:	5/23/2025 $10,000.00 Single Well Bond
Lustre Oil Company LLC Winnett MT	898 G2	Canceled Amount: Purpose:	5/23/2025 $10,000.00 Single Well Bond
Ritchie Exploration, Inc. Wichita KS	116 G1	Canceled Amount: Purpose:	5/19/2025 $10,000.00 Multiple Well Bond

Forfeited

Summit Gas Resources, Inc. Sheridan WY	676 U1	Forfeited Amount: Purpose:	6/2/2025 $9,000.00 UIC Limited Bond
Summit Gas Resources, Inc. Sheridan WY	676 M1	Forfeited Amount: Purpose:	6/2/2025 $50,000.00 Multiple Well Bond

Forfeiture Ordered

D&A Water Disposal LLC Baker MT		825 T1	Forfeiture Ordered Amount: Purpose:	4/10/2025 $15,000.00 UIC Single Well Bond
Surety Bond	$15,000.00	Lexon Insurance Company		ACT
D&A Water Disposal LLC Baker MT		825 G1	Forfeiture Ordered Amount: Purpose:	4/10/2025 $10,000.00 Single Well Bond
Surety Bond	$10,000.00	Lexon Insurance Company		ACT

Montana Board of Oil and Gas Conservation
Summary of Bond Activity

4/10/2025 Through 6/10/2025

Letter Sent

Hamilton, John E.		193 G1	Letter Sent	4/23/2025
Miles City MT			Amount:	$5,000.00
			Purpose:	Domestic Well Bond
Certificate of Deposit	$5,000.00	STOCKMAN BANK, MILES CITY		ACT

Summit Gas Resources, Inc.	676 U1	Letter Sent	4/17/2025
Sheridan WY		Amount:	$9,000.00
		Purpose:	UIC Limited Bond

Summit Gas Resources, Inc.	676 M1	Letter Sent	4/17/2025
Sheridan WY		Amount:	$50,000.00
		Purpose:	Multiple Well Bond

148-2025	Heritage Energy Operating, LLC	Hearing on Heritage Energy Operating, LLC's application for permit to drill, E. Poff Trust 13-12-1 1H well, T25N-R56E: 1, 12, 13; protest filed by Phoenix Operating LLC.		☐
149-2025 20-2025 F	Kraken Oil & Gas LLC	Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 28N-57E-10: all, 15: all, 22: all, 27: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Operations must commence within one year of date of order. Amend Order 195-2011 to clarify that said order is limited to the Charley 15-10 #1-H well. Amend Order 308-2014 to clarify that said order is limited to the Nelson 27-22 1H well. Vacate Order 191-2014 (Authorization to drill up to four additional Bkn/TF wells, PSU, 28N-57E-22: all, 27: all).	*Related applications: 149-2025, 150-2025* *10 & 15: PSU, order 194-2011; pooling, order 195-2011* *22 & 27: PSU, order 189-2014; pooling, order 308-2014; well density, order 191-2014*	☐
150-2025 21-2025 F	Kraken Oil & Gas LLC	Authorize the drilling of three additional horizontal wells, overlapping temporary spacing unit, Bakken/Three Forks Formation, 28N-57E-10: all, 15: all, 22: all, 27: all, 200' heel/toe setbacks and 500' lateral setbacks.	*Related applications: 149-2025, 150-2025*	☐
151-2025 22-2025 F	Kraken Oil & Gas LLC	Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 28N-57E-9: all, 16: all, 21: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Operations must commence within one year of date of order. Amend Order 64-2011 to clarify that said order is limited to the Swindle 16-9 #1H well. Vacate Order 33-2011 (TSU comprised of 28N-57E-20: all, 21: all, Bkn/TF Formation), 418-2011 (Amend Order 33-2011 to allow 200' heel/toe and 1320' lateral setback in TSU comprised of 28N-57E-20: all, 21: all, Bkn/TF Formation) and Order 419-2011 (Authorization to drill a second Bakken/Three Forks wells, TSU, 28N-57E-20: all, 21: all. Authorization for second well expires 12/15/2012.)	*Related applications: 151-2025, 152-2025* *Includes sections 21 that is also in Phoenix dockets 159 & 160-2025* *9 & 16: PSU, order 64-2011* *21: TSU w/section 20, order 33-2011; well density, order 419-2011*	☐
152-2025 23-2025 F	Kraken Oil & Gas LLC	Authorize the drilling of three additional horizontal wells, overlapping temporary spacing unit, Bakken/Three Forks Formation, 28N-57E-9: all, 16: all, 21: all, 200' heel/toe setbacks and 500' lateral setbacks.	*Related applications: 151-2025, 152-2025* *Includes sections 21 that is also in Phoenix dockets 159 & 160-2025*	☐
153-2025 24-2025 F	Kraken Oil & Gas LLC	Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 28N-57E-8: all, 17: all, 20: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Operations must commence within one year of date of order. Amend Order 456-2011 to clarify that said order is limited to the Gobbs 17-8 #1-H well. Vacate Order 33-2011 (TSU comprised of 28N-57E-20: all, 21: all, Bkn/TF Formation), Order 418-2011 (Amend Order 33-2011 to allow 200' heel/toe and 1320' lateral setback in TSU comprised of 28N-57E-20: all, 21: all, Bkn/TF Formation) and Order 419-2011 (Authorization to drill a second Bakken/Three Forks wells, TSU, 28N-57E-20: all, 21: all. Authorization for second well expires 12/15/2012.)	*Related applications: 153-2025, 154-2025* *Includes sections 20 that is also in Phoenix dockets 159 & 160-2025* *8 & 17: PSU, order 193-2011; pooling, order 456-2011* *20: TSU w/section 20, order 33-2011; well density, order 419-2011*	☐

154-2025	Kraken Oil & Gas LLC	Authorize the drilling of three additional horizontal wells, overlapping temporary spacing unit, Bakken/Three Forks Formation, 28N-57E-8: all, 17: all, 20: all, 200' heel/toe setbacks and 500' lateral setbacks.		*Related applications: 153-2025, 154-2025* *Includes sections 20 that is also in Phoenix dockets 159 & 160-2025*	☐
155-2025 25-2025 F	Kraken Oil & Gas LLC	Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 28N-57E-30: all, 31: all and 27N-57E-6: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Operations must commence within one year of date of order. Amend Order 58-2014 to clarify that said order is limited to the Scottsman 1-30H well. Vacate Order 59-2014 (Authorization to drill up to three additional Bkn/TF wells, PSU, 28N-57E-30: all, 31: all), Order 421-2011 (Authorization to drill a second Bkn/TF wells, TSU, 27N-57E-6: all, 7: all, 200' heel/toe, 500' lateral setback for second well. Authorization for second well expires 12/15/2012.) and Order 469-2011 (TSU, Bkn/TF Formations, 27N-57E-6: all, 7: all).	**Continued**	*Related applications: 155-2025, 156-2025* *30 & 31: PSU, order 57-2014; pooled, order 58-2014; well density, order 59-2014* *6 & 7: TSU, order 469-2011; well density, order 421-2011* *Continued to the August hearing, email received 6/2/25.*	☐
156-2025 26-2025 F	Kraken Oil & Gas LLC	Authorize the drilling of three additional horizontal wells, overlapping temporary spacing unit, Bakken/Three Forks Formation, 28N-57E-30: all, 31: all and 27N-57E-6: all, 200' heel/toe setbacks and 500' lateral setbacks.	**Continued**	*Related applications: 155-2025, 156-2025* *Continued to the August hearing, email received 6/2/25.*	☐
157-2025 27-2025 F	Kraken Oil & Gas LLC	Designate temporary spacing unit, Bakken/Three Forks Formation, 27N-57E-7: all, 18: all, 19: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Operations must commence within one year of date of order. Vacate Order 421-2011 (Authorization to drill a second Bkn/TF wells, TSU, 27N-57E-6: all, 7: all, 200' heel/toe, 500' lateral setback for second well. Authorization for second well expires 12/15/2012.) and Order 469-2011 (TSU, Bkn/TF Formations, 27N-57E-6: all, 7: all).	**Continued**	*Related applications: 157-2025, 158-2025* *6 & 7: TSU, order 469-2011; well density, order 421-2011* *Continued to the August hearing, email received 6/2/25.*	☐
158-2025	Kraken Oil & Gas LLC	Authorize the drilling of three additional horizontal wells, temporary spacing unit, Bakken/Three Forks Formation, 27N-57E-7: all, 18: all, 19: all, 200' heel/toe setbacks and 500' lateral setbacks.	**Continued**	*Related applications: 157-2025, 158-2025* *Continued to the August hearing, email received 6/2/25.*	☐
159-2025 28-2025 F	Phoenix Operating LLC	Temporary spacing unit, Bakken/Three Forks Formation, 28N-56E-24: all and 28N-57E-19: all, 20: all, 21: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Operations must commence within one year of date of order. Vacate Orders 109-2010 & 341-2011 (TSU, Bkn Formation, 28N-57E-18: all, 19: all; 200' toe & heel, 1320' lateral setbacks. (Setback amended to 1320/200 by Order 341-2011.), 218-2010 (TSU, Bkn Formation, 28N-56E-13: all, 24: all), Order 33-2011 (TSU, Bkn Formation, 28N-57E-20: all, 21: all), and Order 380-2011 (pertaining only to 28N-57E-19: all, 20: all, 21: all).	**Continued**	*Related applications: 159-2025, 160-2025* *Includes sections 20, 21, & 24 that are also in Kraken dockets 151, 152, 153, 154, 188, & 189-2025* *Continued to the August hearing, email received 6/2/25.*	☐
160-2025 29-2025 F	Phoenix Operating LLC	Authorize the drilling of three additional horizontal wells, temporary spacing unit, Bakken/Three Forks Formation, 28N-56E-24: all and 28N-57E-19: all, 20: all, 21: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion.	**Continued**	*Related applications: 159-2025, 160-2025* *Includes sections 20, 21, & 24 that are also in Kraken dockets 151, 152, 153, 154, 188, & 189-2025* *Continued to the August hearing, email received 6/2/25.*	☐

161-2025	Black Dog Operating, LLC	Hearing on Black Dog Operating, LLC's 4 application for permits to drills in T29N-R57E-13: SWSE and 4 applications for permits to drill in T29N-R57E-2: NWNE; protest filed by Phoenix Operating LLC.	**Withdrawn**	*Protest withdrawn, email received 5/19/25.*	☐
162-2025	Thor Resources USA, LLC	Temporary spacing unit, vertical gas test well, formations below top of Madison Formation, 33N-4E-14: S2, 23: N2, 900' setbacks.	**Withdrawn**	*900 ft setback request?* *Exisitng Nisku gas well in center of section 14* *Withdrawn, email received 5/14/25.*	☐
163-2025	Heritage Energy Operating, LLC	Designate temporary spacing unit, Bakken/Three Forks Formation, 26N-56E-19: all, 30: all, 31: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Vacate Order 362-2011 (TSU, Bkn/TF Formations, 26N-56E-30: all, 31: all).	**Protest ??**	*Operations must commence by date?* *Related applications: 163-2025, 164-2025* *Phoenix Operating intends to protest, 6/10/25.*	☐
164-2025	Heritage Energy Operating, LLC	Authorize the drilling of three additional horizontal wells, temporary spacing unit, Bakken/Three Forks Formation, 26N-56E-19: all, 30: all, 31: all, 200' heel/toe setbacks and 500' lateral setbacks.	**Protest ??**	*Related applications: 163-2025, 164-2025* *Phoenix Operating intends to protest, 6/10/25.*	☐
165-2025	Heritage Energy Operating, LLC	Designate temporary spacing unit, Bakken/Three Forks Formation, 26N-56E-6: all, 7: all, 18: all, and 27N-56E-31: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion.	**Protest ??**	*Operations must commence by date?* *Related applications: 165-2025, 166-2025* *Well to east drilled on 660' setback* *Phoenix Operating intends to protest, 6/10/25.*	☐
166-2025	Heritage Energy Operating, LLC	Authorize the drilling of three additional horizontal wells, temporary spacing unit, Bakken/Three Forks Formation, 26N-56E-6: all, 7: all, 18: all, and 27N-56E-31: all, 200' heel/toe setbacks and 500' lateral setbacks.	**Protest ??**	*Well to east drilled on 660' setback* *Related applications: 165-2025, 166-2025* *Phoenix Operating intends to protest, 6/10/25.*	☐
167-2025	Heritage Energy Operating, LLC	Designate temporary spacing unit, Bakken/Three Forks Formation, 26N-55E-24: all, 25: all, 36: all, and 25N-55E-1: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Vacate Order 367-2011 (TSU, Bkn/TF Formations, 26N-55E-25: all, 36: all), Order 193-2010 (TSU, Bkn/TF Formations, 25N-55E-1: all, 12: all), Order 366-2011 (Vacate Order 11-2009; Create TSU, Bkn/TF Formations, 26N-55E-13: all, 24: all), and partially vacate Order 166-2011 pertaining only to 25N-55E-1: all, 12: all setbacks.		*Operations must commence by date?* *Related applications: 167-2025, 168-2025*	☐
168-2025	Heritage Energy Operating, LLC	Authorize the drilling of three additional horizontal wells, temporary spacing unit, Bakken/Three Forks Formation, 26N-55E-24: all, 25: all, 36: all, and 25N-55E-1: all, 200' heel/toe setbacks and 500' lateral setbacks.		*Related applications: 167-2025, 168-2025*	☐
169-2025	Heritage Energy Operating, LLC	Designate temporary spacing unit, Bakken/Three Forks Formation, 26N-55E-1: all, 12: all, 13: all, and 27N-55E-36: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Vacate Orders 355-2011 (TSU, B/TF Formations, 26N-55E-1: all, 12: all) and 366-2011 (Vacate Order 11-2009; Create TSU, Bkn/TF Formations, 26N-55E-13: all, 24: all).		*Operations must commence by date?* *Related applications: 169-2025, 170-2025*	☐
170-2025	Heritage Energy Operating, LLC	Authorize the drilling of three additional horizontal wells, temporary spacing unit, Bakken/Three Forks Formation, 26N-55E-1: all, 12: all, 13: all, and 27N-55E-36: all, 200' heel/toe setbacks and 500' lateral setbacks.		*Related applications: 169-2025, 170-2025*	☐

171-2025	Heritage Energy Operating, LLC	Designate temporary spacing unit, Bakken/Three Forks Formation, 25N-57E-8: all, 9: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Vacate Orders 44-2012 (TSU, Bkn/TF Formations, 25N-57E-5: all, 8: all,[ORDER EXPIRES 3/8/2013.]) and Order 380-2011 (pertaining only to 25N-57E-8: all, 9: all).		*Operations must commence by date?* *Related applications: 171-2025, 172-2025*	☐
172-2025	Heritage Energy Operating, LLC	Authorize the drilling of three additional horizontal wells, temporary spacing unit, Bakken/Three Forks Formation,25N-57E-8: all, 9: all, 200' heel/toe setbacks and 500' lateral setbacks.		*Related applications: 171-2025, 172-2025*	☐
173-2025	White Rock Oil & Gas, LLC	Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 23N-57E-23: all, 26: all, 35: all, 200' heel/toe setbacks and 660' lateral setbacks. Apply for permanent spacing within 90 days of completion. Amend Order 339-2004 to clarify that said order is limited to the Steinbeisser 21-23H well. Amend Order 80-2005 to clarify that said order is limited to the Larson 14-26H well. Amend Order 98-2005 to clarify that said order is limited to the Steinbeisser 41-34H and Steinbeisser 14-35H wells.		*23: PSU; order 339-2004* *26: PSU, order 80-2005* *35: PSU w/section 34, order 98-2005*	☐
174-2025	White Rock Oil & Gas, LLC	Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 23N-57E-22: all, 27: all, 34: all, 200' heel/toe setbacks and 660' lateral setbacks. Apply for permanent spacing within 90 days of completion. Amend Order 212-2005 to clarify that said order is limited to the Steinbeisser 14-22H, Steinbeisser 31X-34, and Steinbeisser 34-22H wells. Amend Order 98-2005 to clarify that said order is limited to the Steinbeisser 41-34H and Steinbeisser 14-35H wells.		*22 & 27: PSU, order 211-2005; pooled, order 212-2005; well density, order 183-2014* *34: PSU w/section 35, order 98-2005*	☐
175-2025	White Rock Oil & Gas, LLC	Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 23N-57E-22: all, 23: all, 26: all, 27: all, 34: all, 35: all, well at a location proximate to the common boundary between 23N-57E-23, 26, 35 and 23N-57E-22, 27, 34, 200' heel/toe setbacks. Apply for permanent spacing within 90 days of completion. The overlapping temporary spacing unit shall be limited to production from the proposed horizontal well.		*23: PSU, order 339-2004* *26: PSU, order 80-2005* *35: PSU w/section 34, order 98-2005* *22 & 27: PSU, order 211-2005; pooled, order 212-2005; well density, order 183-2014* *34: PSU w/section 35, order 98-2005*	☐
176-2025	MorningStar Operating LLC	Authorize the drilling of an additional horizontal well, permanent spacing unit, Bakken/Three Forks Formation, 25N-53E-3 all, 10 all, 200' heel/toe setbacks and 500' lateral setbacks.	**Withdrawn**	*East & west adjacent spacing units developed on 660' setbacks.* *Withdrawn, email received 5/28/25.*	☐
177-2025	MorningStar Operating LLC	Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 23N-57E-36: all, 23N-58E-31: all, 22N-57E-1: all, 22N-58E-6: all, well at a location proximate to the common boundary between 23N-57E-36, 22N-57E-1 and 23N-58E-31, 22N-58E-6, 200' heel/toe setbacks. Apply for permanent spacing within 90 days of completion. The overlapping temporary spacing unit shall be limited to production from the proposed horizontal well with no allocation to portions of any existing permanent spacing unit located outside of the proposed overlapping temporary spacing unit boundaries.	**Withdrawn**	*31: PSU w/section 30, order 203-2006* *6: PSU, order 368-2005* *1 & 36: PSU, order 76-2005* *Withdrawn, email received 5/28/25.*	☐

178-2025	MorningStar Operating LLC	Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 22N-57E-1: all, 2: all, 11: all, 12: all, well at a location proximate to the common boundary between 22N-57E-1, 12, and 22N-57E-2, 11, 200' heel/toe setbacks. Apply for permanent spacing within 90 days of completion. The overlapping temporary spacing unit shall be limited to production from the proposed horizontal well with no allocation to portions of any existing permanent spacing unit located outside of the proposed overlapping temporary spacing unit boundaries.	**Withdrawn**	*1: PSU w/section 31, order 76-2005* *2: PSU, order 264-2006; pooled order 265-2006* *11: PSU, order 43-2006* *12: PSU, order 135-2006* *Withdrawn, email received 5/28/25.*	☐
179-2025	MorningStar Operating LLC	Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 25N-54E-23: all, 24: all, 25: all, 26: all, well at a location proximate to the common boundary between 25N-54E-23, 24, and 25N-54E-25, 26, 200' heel/toe setbacks. Apply for permanent spacing within 90 days of completion. The overlapping temporary spacing unit shall be limited to production from the proposed horizontal well.	**Withdrawn**	*23: PSU, order 255-2005* *24: PSU, order 13-2006* *25: PSU, order 258-2003* *26: PSU, order 14-2005* *Withdrawn, email received 5/28/25.*	☐
180-2025	MorningStar Operating LLC	Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 22N-59E-25: all, 26: all, 35: all, 36: all, and 21N-59E-1: all, 2: well at a location proximate to the common boundary between 22N-59E: 25, 36, 21N-59E: 1 and 22N-59E: 26, 35, 21N-59E: 2, 200' heel/toe setbacks. Apply for permanent spacing within 90 days of completion. The overlapping temporary spacing unit shall be limited to production from the proposed horizontal well. be limited to production from the proposed horizontal well.	**Withdrawn**	*25 & 26: OTSU, order 3-2010* *25: PSU, order 5-2005* *26: PSU, order 331-2004* *35: PSU, order 366-2005* *36: PSU, order 488-2005* *1: PSU, order 298-2010* *2: PSU, order 53-2008* *Withdrawn, email received 5/28/25.*	☐
181-2025	Phoenix Operating LLC	Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 23N-58E-1: all, 12: all, and 24N-58E-25: all, 36: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Operations must commence within one year of date of order. Vacate Order 241-2012 (Exception to drill up to three additional wells, Bkn/TF Formation, PSU, 23N-58E-1, 12).	**Continued**	*Related applications: 181-2025, 182-2025* *1 & 12: PSU, order 167-2012; pooled, order 239-2012* *25 & 26: TSU, order 139-2011 (no request to vacate)* *Existing well operated by White Rock* *Continued to the August hearing, email received 6/3/25.*	☐
182-2025	Phoenix Operating LLC	Authorize the drilling of three additional horizontal wells, overlapping temporary spacing unit, Bakken/Three Forks Formation, 23N-58E-1: all, 12: all, and 24N-58E-25: all, 36: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion.	**Continued**	*Related applications: 181-2025, 182-2025* *Continued to the August hearing, email received 6/3/25.*	☐
183-2025	Phoenix Operating LLC	Permanent spacing unit, Bakken/Three Forks Formation, 29N-57E-24: all, 25: all, 36: all (Samurai 36-25-24 1H, Samurai 36-25-24 2H, Samurai 36-25-24 3H, and Samurai 36-25-24 4H).		*TSU, order 70-2023 (operations date amended by order 55-2024)* *Well density (4 total), order 71-2023* *Related applications: 183-2025, 184-2025*	☐
184-2025	Phoenix Operating LLC	Pooling, permanent spacing unit, Bakken/Three Forks Formation, 29N-57E-24: all, 25: all, 36: all (Samurai 36-25-24 1H, Samurai 36-25-24 2H, Samurai 36-25-24 3H, and Samurai 36-25-24 4H). Non-consent penalties requested.		*Related applications: 183-2025, 184-2025*	☐

185-2025	Kraken Oil & Gas LLC	Amend Order 8-2023, 4-2024 (Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 24N-59E-4: all, 5: all, 8: all, 9: all, 16: all, 17: all, well at a location proximate to the common boundary between the overlapping temporary spacing unit 24N-59E-4, 9, 16, and overlapping temporary spacing unit 24N-59E-5, 8, 17. Apply for permanent spacing within 90 days of completion. Operations must commence within one year of date of order. The overlapping temporary spacing unit shall be limited to production from the proposed horizontal well.) Amend that operations must commence by 6/12/2026.			☐
186-2025 30-2025 F	Kraken Oil & Gas LLC	Designate temporary spacing unit, Bakken/Three Forks Formation, 27N-56E-1: all, 12: all, 13: all, 24: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Operations must commence within one year of date of order.	**Continued**	*Related applications: 186-2025, 187-2025* *Continued to the August hearing, email received 6/2/25.*	☐
187-2025 31-2025 F	Kraken Oil & Gas LLC	Authorize the drilling of three additional horizontal wells, temporary spacing unit, Bakken/Three Forks Formation, 27N-56E-1: all, 12: all, 13: all, 24: all, 200' heel/toe setbacks and 500' lateral setbacks.	**Continued**	*Related applications: 186-2025, 187-2025* *Continued to the August hearing, email received 6/2/25.*	☐
188-2025	Kraken Oil & Gas LLC	Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 28N-56E-13: all, 24: all, 25: all, 36: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Operations must commence within one year of date of order. The overlapping temporary spacing unit shall be limited to the production from the proposed horizontal well. Amend Order 326-2013 to clarify that said order is limited to the Christopher 25-36 #1H well. Vacate Order 218-2010 (TSU, Bkn Formation, 28N-56E-13: all, 24: all) and Order 327-2013 (Exception to drill up to four additional wells, PSU, Bkn/TF Formation, 28N-56E-25: all, 36: all).	**Continued**	*Includes sections 24 that is also in Phoenix dockets 159 & 160-2025* *Related applications: 188-2025, 189-2025* *25 & 36: PSU, order 325-2013; pooling, order 362-2013; well density, order 327-2013* *13 & 14: TSU: order 218-2010* *Continued to the August hearing, email received 6/2/25.*	☐
189-2025	Kraken Oil & Gas LLC	Authorize the drilling of three additional horizontal wells, overlapping temporary spacing unit, Bakken/Three Forks Formation, 28N-56E-13: all, 24: all, 25: all, 36: all, 200' heel/toe setbacks and 500' lateral setbacks.	**Continued**	*Includes sections 24 that is also in Phoenix dockets 159 & 160-2025* *Related applications: 188-2025, 189-2025*	☐
190-2025	Slawson Exploration Company Inc	Designate temporary spacing unit, Bakken/Three Forks Formation, 27N-59E-27: all, 28: all, 33: all, 34: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion.	**Continued**	*Related applications: 190-2025, 191-2025* *Continued to the August hearing, email received 6/9/25.*	☐
191-2025	Slawson Exploration Company Inc	Authorize the drilling of six additional horizontal wells, temporary spacing unit, Bakken/Three Forks Formation, 27N-59E-27: all, 28: all, 33: all, 34: all, 200' heel/toe setbacks and 500' lateral setbacks.	**Continued**	*Related applications: 190-2025, 191-2025* *Continued to the August hearing, email received 6/9/25.*	☐

192-2025	Slawson Exploration Company Inc	Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 26N-59E-2: all, 3: all, 10: all, 11: all, 14: all, 15: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Amend Order 232-2012 to clarify that said order is limited to the Citadel 1-11-2H well. Amend Order 480-2011 to clarify that said order is limited to the Battalion 1-3H well. Amend Order 250-2011 to clarify that said order is limited to the Renegade 1-10H well. Amend Order 231-212 to clarify that said order is limited to the Squadron 1-15-14H well. Vacate Order 48-2021 (Amend Order 224-2012, authorize the drilling of up to three additional horizontal wells from a common pad anywhere within the permanent spacing unit, Bakken/Three Forks Formation, 26N-59E-2: all, 11: all, 200' heel/toe, 500' lateral setbacks. [Authorization not operator-specific.]).		*Related applications: 192-2025, 193-2025* *2 & 11: PSU, order 224-2012; pooled, order 232-2012* *14 & 15: PSU, order 225-2012; pooled, order 231-2012* *3: PSU, order 479-2011; pooled, order 480-2011* *10: PSU, order 249-2011; pooled, order 250-2011*	☐
193-2025	Slawson Exploration Company Inc	Authorize the drilling of four additional horizontal wells, overlapping temporary spacing unit, Bakken/Three Forks Formation, 26N-59E-2: all, 3: all, 10: all, 11: all, 14: all, 15: all, 200' heel/toe setbacks and 500' lateral setbacks.		*Related applications: 192-2025, 193-2025*	☐
194-2025	Rim Operating, Inc.	Permanent spacing unit, Mission Canyon Formation, 34N-58E- 30: SE, 31: NE (Meagher #16-30).	**Withdrawn**	*Larger than statewide spacing unit for Mission Canyon (recompleted under 160 acres)* *Withdrawn, emailed received 5/21/25.*	☐
195-2025	Rim Operating, Inc.	Pooling, permanent spacing unit, Mission Canyon Formation, 34N-58E- 30: SE, 31: NE (Meagher #16-30). Non-consent penalties requested.	**Withdrawn**	*Withdrawn, emailed received 5/21/25.*	☐
196-2025 32-2025 F	Continental Resources Inc	Permanent spacing unit, Bakken/Three Forks Formation, 28N-57E-13: all, 24: all, 25: all (Grindland Federal 2-25H and Grindland Federal 3-25HX).	**Continued**	*TSU, order 18-2024* *Well density (2 total), order 129-2024* *Related applications: 196-2025, 197-2025* *Continued to the August hearing, email received 5/30/25.*	☐
197-2025 33-205 F	Continental Resources Inc	Pooling, permanent spacing unit, Bakken/Three Forks Formation, 28N-57E-13: all, 24: all, 25: all (Grindland Federal 2-25H and Grindland Federal 3-25HX). Non-consent penalties requested.	**Continued**	*Related applications: 196-2025, 197-2025* *Continued to the August hearing, email received 5/30/25.*	☐
198-2025 34-2025 F	Continental Resources Inc	Permanent spacing unit, Bakken/Three Forks Formation, 28N-57E-14: all, 23: all, 26: all (Courtney FIU 4-26H and Courtney Federal 3-26H).	**Continued**	*TSU, order 17-2024* *Well density (3 total), orders 130-2024 & 161-2024* *Related applications: 198-2025, 199-2025* *Continued to the August hearing, email received 5/30/25.*	☐
199-2025 35-2025 F	Continental Resources Inc	Pooling, permanent spacing unit, Bakken/Three Forks Formation, 28N-57E-14: all, 23: all, 26: all (Courtney FIU 4-26H and Courtney Federal 3-26H). Non-consent penalties requested.	**Continued**	*Related applications: 198-2025, 199-2025* *Continued to the August hearing, email received 5/30/25.*	☐

200-2025 36-2025 F	Continental Resources Inc	Permanent spacing unit, Bakken/Three Forks Formation, 28N-57E-13: all, 14: all, 23: all, 24: all, 25: all, 26: all (Courtney FIU 5-26HSL).	**Continued**	*TSU, order 131-2024* *Related applications: 200-2025, 201-2025* *Continued to the August hearing, email received 5/30/25.*	☐
201-2025 37-2025 F	Continental Resources Inc	Pooling, permanent spacing unit, Bakken/Three Forks Formation, 28N-57E-13: all, 14: all, 23: all, 24: all, 25: all, 26: all (Courtney FIU 5-26HSL). Non-consent penalties requested.	**Continued**	*Related applications: 200-2025, 201-2025* *Continued to the August hearing, email received 5/30/25.*	☐
202-2025	Black Gold Energy Resource Development, LLC	Change of Operator from Black Gold Energy Resource Development, LLC to Black Gold Energy Indian Mound Facility, Inc.			☐
203-2025	West Shore Energy LLC	Change of Operator from Black Gold Energy Indian Mound Facility, Inc. to West Shore Energy LLC.			☐
204-2025	White Rock Oil & Gas, LLC	Approval to drill, Class II SWD Injection well (Candee 1H SWD), Dakota and Lakota Formations, T24N-R53E-6: NW NE. Aquifer exemption requested.	**Default**		☐
205-2025	White Rock Oil & Gas, LLC	Convert the BR 41-35H 52 well, T25N-R52E-35: NE NE (API # 083-22107) to Class II Injection well, Dakota and Lakota Formations. Aquifer exemption requested.	**Default**		☐
206-2025	Coyote Resources LLC	Convert the Big Rose Colony 1-34 well, T34N-R1W-34: NW NW (API # 101-24287) to Class II Injection well, Duperow Formation.	**Continued**	*Injection interval notice issue, continued to August.*	☐
101-2025	Phoenix Operating LLC	Temporary spacing unit, Bakken/Three Forks Formation, 28N-57E-6: all, 7: all, 18: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Operations must commence within one year of date of order.Vacate Orders 109-2010 & 341-2011 (TSU, Bkn Formation, 28N-57E-18: all, 19: all; 200' toe & heel, 1320' lateral setbacks. (Setback amended to 1320/200 by Order 341-2011.), 219-2010 (TSU, Bkn Formation, 28N-57E-6: all, 7: all) and Order 380-2011 (pertaining only to 28N-57E-6: all, 7: all, 18: all)	**Continued**	*Related applications: 101-2025, 102-2025* *Continued to the June hearing, email received 4/3/25.* *Continued to the August hearing, email received 6/2/25.*	☐
102-2025	Phoenix Operating LLC	Authorize the drilling of three additional horizontal wells, temporary spacing unit, Bakken/Three Forks Formation, 28N-57E-6: all, 7: all, 18: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion.	**Continued**	*Related applications: 101-2025, 102-2025* *Continued to the June hearing, email received 4/3/25.* *Continued to the August hearing, email received 6/2/25.*	☐
109-2025	Kraken Oil & Gas LLC	Designate temporary spacing unit, Bakken/Three Forks Formation, 28N-58E-27: all, 28: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Operations must commence within one year of date of order.	**Continued**	*Related applications: 109-2025, 110-2025* *Continued to the June hearing, email received 4/9/25.* *Continued to the August hearing, email received 6/2/25.*	☐

110-2025	Kraken Oil & Gas LLC	Authorize the drilling of three additional horizontal wells, temporary spacing unit, Bakken/Three Forks Formation, 28N-58E-27: all, 28: all, 200' heel/toe setbacks and 500' lateral setbacks.	**Continued**	*Related applications: 109-2025, 110-2025* *Continued to the June hearing, email received 4/9/25.* *Continued to the August hearing, email received 6/2/25.*	☐
130-2025	Continental Resources Inc	Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 25N-57E-6: all, 7: all, 18: all, 19: all, 200' heel/toe setbacks and 500' lateral setbacks. Apply for permanent spacing within 90 days of completion. Operations must commence within one year of date of order. The overlapping temporary spacing unit shall be limited to the production from the proposed horizontal well. Amend Order 466-2012 to clarify that said order is limited to the Conaway 1-19H well. Vacate Order 467-2012 (drill up to three additional wells, PSU, Bkn/TF Formation, 25N-57E-18: all, 19: all).		*Section 24 to west was drilled on 660' lateral setback, section 17 to east had 500' setback authorized when well drilled.* *Sections 18 & 19: PSU, order 465-2012; pooled, order 466-2012* *Related applications: 131-2025, 15-2025, 49-2025, 50-2025* *Continued to the June hearing, email received 4/1/25.*	☐
131-2025	Continental Resources Inc	Authorize the drilling of two additional horizontal wells, overlapping temporary spacing unit, Bakken/Three Forks Formation, 25N-57E-6: all, 7: all, 18: all, 19: all, 200' heel/toe setbacks and 500' lateral setbacks.		*Section 24 to west was drilled on 660' lateral setback* *Related applications: 131-2025, 15-2025, 49-2025, 50-2025* *Continued to the June hearing, email received 4/1/25.*	☐
142-2025	MorningStar Operating LLC	Designate overlapping temporary spacing unit, Bakken/Three Forks Formation, 25N-54E-33: all, 34: all and 24N-54E-1: all, 2: all, 11: all, 12: all, well at a location proximate to the common boundary between 25N-54E-33: all, 24N-54E-2: all, 11: all and 25N-54E-34: all, 24N-54E-1: all, 12: all, 200' heel/toe setbacks. Apply for permanent spacing within 90 days of completion. The overlapping temporary spacing unit shall be limited to production from the proposed horizontal well.		*Continued to the June hearing, email received 3/24/25.* *W/2 S33 & S2: PSU, order 113-2005* *S2 & S33: OTSU, order 19-2011* *S1 & S34: PSU, order 306-2003; additional well, order 101-2008* *S12 & S13: PSU, order 149-2004, additonal wells, orders 405-2005 & 260-2007* *S11: PSU, order 188-2002 (2 wells); additional well, order 339-2006* *S33 NE & SE qtr: 160 statewide spacing units*	☐
207-2025	Bad Water Disposal, LLC	Show Cause: failure to file injection reports and pay administrative fees.			☐
208-2025	Bad Water Disposal, LLC	Show Cause: why additional penalties should not be imposed for failure to pay the annual injection fee for its permitted injection well, the late fee assessed for nonpayment, and for failure to remedy the compliance issues outlined in Administrative Order 5-A-2025. The total due in injection well fees and penalties is now $300. Board staff has authority to dismiss the docket if Bad Water Disposal, LLC achieves compliance prior to the June 12, 2025, public hearing.			☐
209-2025	Big Sky Energy, LLC	Show Cause: why additional penalties should not be imposed for failure to pay the annual injection fee for its permitted injection well and the late fee assessed for nonpayment. The total due in injection well fees and penalties is now $300. Board staff has authority to dismiss the docket if Big Sky Energy, LLC achieves compliance prior to the June 12, 2025, public hearing.			☐

210-2025	Big Sky Energy, LLC	Show Cause: why it should not immediately plug and abandon or transfer its wells in Carbon, Golden Valley, and Stillwater Counties, Montana.			☐
211-2025	D90 Energy, LLC	Show Cause: why additional penalties should not be imposed for failure to pay the annual injection fee for its permitted injection well and the late fee assessed for nonpayment. The total due in injection well fees and penalties is now $3,900. Board staff has authority to dismiss the docket if D90 Energy LLC achieves compliance prior to the June 12, 2025, public hearing.			☐
212-2025	D90 Energy, LLC	Show Cause: why it should not immediately plug and abandon or transfer its wells in Sheridan County, Montana.			☐
213-2025	Diamond Halo Group LLC	Show Cause: failure to pay the administrative penalty assessed for delinquent reporting.	**Dismissed**	*The delinquent reports/fee was received. Docket administratively dismissed in accordance with policy.*	☐
214-2025	Enneberg Energy, Inc.	Show Cause: failure to pay the administrative penalty assessed for delinquent reporting.	**Dismissed**	*The delinquent reports/fee was received. Docket administratively dismissed in accordance with policy.*	☐
215-2025	McOil Montana One LLC	Show Cause: failure to file production reports and pay administrative fees.			☐
216-2025	Ranck Oil Company, Inc.	Show Cause: failure to pay the administrative penalty assessed for delinquent reporting.	**Dismissed**	*The delinquent reports/fee was received. Docket administratively dismissed in accordance with policy.*	☐
217-2025	XOIL Inc.	Show Cause: why additional penalties should not be assessed for failure to restore the Richardson-Hoven 1-11 (API 25-091-21511) and Simard 26-16 (API 25-085-21430) locations.			☐
218-2025	Montana Energy Company, LLC	Show Cause: why additional penalties should not be imposed for failure to pay the annual injection fee for its permitted injection well and the late fee assessed for nonpayment. The total due in injection well fees and penalties is now $6,300. Board staff has authority to dismiss the docket if Montana Energy Company, LLC achieves compliance prior to the June 12, 2025, public hearing.			☐
90-2025	Montana Energy Company, LLC	Show Cause: why penalties, which could include its production being declared illegal in accordance with ARM 36.22.1245, should not be imposed for failure to promptly remedy the compliance issues outlined in Administrative Order 15-A-2024 and to provide a plan for removing the remaining fluids from the emergency pits.			☐
92-2025	Yellowstone Petroleums, Inc.	Show Cause: why additional penalties should not be assessed for failure to plug and abandon the Essex-Thompson 1 and Myhre 3-25 wells as required by Board Order 48-2024.			☐

ALL APPLICATIONS, 6/12/2025

(In Order of Publication)

Docket	Applicant / Respondent	Status	Request
148-2025	Heritage Energy Operating, LLC		APD Protest
149-2025	Kraken Oil & Gas LLC		Temp. Spacing; Vacate Order
150-2025	Kraken Oil & Gas LLC		Well Density
151-2025	Kraken Oil & Gas LLC		Temp. Spacing; Vacate Order
152-2025	Kraken Oil & Gas LLC		Well Density
153-2025	Kraken Oil & Gas LLC		Temp. Spacing; Vacate Order
154-2025	Kraken Oil & Gas LLC		Well Density
155-2025	Kraken Oil & Gas LLC	Continued	Temp. Spacing; Vacate Order
156-2025	Kraken Oil & Gas LLC	Continued	Well Density
157-2025	Kraken Oil & Gas LLC	Continued	Temp. Spacing; Vacate Order
158-2025	Kraken Oil & Gas LLC	Continued	Well Density
159-2025	Phoenix Operating LLC	Continued	Temp. Spacing; Vacate Order
160-2025	Phoenix Operating LLC	Continued	Well Density
161-2025	Black Dog Operating, LLC	Withdrawn	APD Protest
162-2025	Thor Resources USA, LLC	Withdrawn	Temp. Spacing
163-2025	Heritage Energy Operating, LLC	Protest ??	Temp. Spacing; Vacate Order
164-2025	Heritage Energy Operating, LLC	Protest ??	Well Density
165-2025	Heritage Energy Operating, LLC	Protest ??	Temp. Spacing
166-2025	Heritage Energy Operating, LLC	Protest ??	Well Density
167-2025	Heritage Energy Operating, LLC	Protest ??	Temp. Spacing; Vacate Order
168-2025	Heritage Energy Operating, LLC	Protest ??	Well Density
169-2025	Heritage Energy Operating, LLC	Protest ??	Temp. Spacing; Vacate Order
170-2025	Heritage Energy Operating, LLC	Protest ??	Well Density
171-2025	Heritage Energy Operating, LLC	Continued	Temp. Spacing; Vacate Order
172-2025	Heritage Energy Operating, LLC	Continued	Well Density
173-2025	White Rock Oil & Gas, LLC		Temp. Spacing
174-2025	White Rock Oil & Gas, LLC		Temp. Spacing
175-2025	White Rock Oil & Gas, LLC		Temp. Spacing
176-2025	MorningStar Operating LLC	Withdrawn	Well Density
177-2025	MorningStar Operating LLC	Withdrawn	Temp. Spacing
178-2025	MorningStar Operating LLC	Withdrawn	Temp. Spacing
179-2025	MorningStar Operating LLC	Withdrawn	Temp. Spacing
180-2025	MorningStar Operating LLC	Withdrawn	Temp. Spacing
181-2025	Phoenix Operating LLC	Continued	Temp. Spacing; Vacate Order
182-2025	Phoenix Operating LLC	Continued	Well Density
183-2025	Phoenix Operating LLC		Spacing
184-2025	Phoenix Operating LLC		Pooling
185-2025	Kraken Oil & Gas LLC		Spacing Amdt
186-2025	Kraken Oil & Gas LLC	Continued	Temp. Spacing
187-2025	Kraken Oil & Gas LLC	Continued	Well Density
188-2025	Kraken Oil & Gas LLC	Continued	Temp. Spacing; Vacate Order

189-2025	Kraken Oil & Gas LLC	Continued	Well Density
190-2025	Slawson Exploration Company Inc	Continued	Temp. Spacing
191-2025	Slawson Exploration Company Inc	Continued	Well Density
192-2025	Slawson Exploration Company Inc		Temp. Spacing; Vacate Order
193-2025	Slawson Exploration Company Inc		Well Density
194-2025	Rim Operating, Inc.	Withdrawn	Spacing
195-2025	Rim Operating, Inc.	Withdrawn	Pooling
196-2025	Continental Resources Inc	Continued	Spacing
197-2025	Continental Resources Inc	Continued	Pooling
198-2025	Continental Resources Inc	Continued	Spacing
199-2025	Continental Resources Inc	Continued	Pooling
200-2025	Continental Resources Inc	Continued	Spacing
201-2025	Continental Resources Inc	Continued	Pooling
202-2025	Black Gold Energy Resource Development, LLC		Change of Operator
203-2025	West Shore Energy LLC		Change of Operator
204-2025	White Rock Oil & Gas, LLC	Default	Class II Permit
205-2025	White Rock Oil & Gas, LLC	Default	Class II Permit
206-2025	Coyote Resources LLC	Continued	Class II Permit
101-2025	Phoenix Operating LLC	Continued	Temp. Spacing; Vacate Order
102-2025	Phoenix Operating LLC	Continued	Well Density
109-2025	Kraken Oil & Gas LLC	Continued	Temp. Spacing
110-2025	Kraken Oil & Gas LLC	Continued	Well Density
130-2025	Continental Resources Inc		Temp. Spacing; Vacate Order
131-2025	Continental Resources Inc		Well Density
142-2025	MorningStar Operating LLC		Temp. Spacing
207-2025	Bad Water Disposal, LLC		Show-Cause
208-2025	Bad Water Disposal, LLC		Show-Cause
209-2025	Big Sky Energy, LLC		Show-Cause
210-2025	Big Sky Energy, LLC		Show-Cause
211-2025	D90 Energy, LLC		Show-Cause
212-2025	D90 Energy, LLC		Show-Cause
213-2025	Diamond Halo Group LLC	Dismissed	Show-Cause
214-2025	Enneberg Energy, Inc.	Dismissed	Show-Cause
215-2025	McOil Montana One LLC		Show-Cause
216-2025	Ranck Oil Company, Inc.	Dismissed	Show-Cause
217-2025	XOIL Inc.		Show-Cause
218-2025	Montana Energy Company, LLC		Show-Cause
90-2025	Montana Energy Company, LLC		Show-Cause
92-2025	Yellowstone Petroleums, Inc.		Show-Cause

APPLICATIONS TO HEAR. 6/12/2025

(In Order of Hearing)

Docket	Applicant	Status	Request
149-2025	Kraken Oil & Gas LLC (20-2025 FED)		Temp. Spacing; Vacate Order
150-2025	Kraken Oil & Gas LLC (21-2025 FED)		Well Density
151-2025	Kraken Oil & Gas LLC (22-2025 FED)		Temp. Spacing; Vacate Order
152-2025	Kraken Oil & Gas LLC (23-2025 FED)		Well Density
153-2025	Kraken Oil & Gas LLC (24-2025 FED)		Temp. Spacing; Vacate Order
154-2025	Kraken Oil & Gas LLC		Well Density
185-2025	Kraken Oil & Gas LLC		Spacing Amdt
148-2025	Heritage Energy Operating, LLC		APD Protest
163-2025	Heritage Energy Operating, LLC	Protest ??	Temp. Spacing; Vacate Order
164-2025	Heritage Energy Operating, LLC	Protest ??	Well Density
165-2025	Heritage Energy Operating, LLC	Protest ??	Temp. Spacing
166-2025	Heritage Energy Operating, LLC	Protest ??	Well Density
167-2025	Heritage Energy Operating, LLC	Protest ??	Temp. Spacing; Vacate Order
168-2025	Heritage Energy Operating, LLC	Protest ??	Well Density
169-2025	Heritage Energy Operating, LLC	Protest ??	Temp. Spacing; Vacate Order
170-2025	Heritage Energy Operating, LLC	Protest ??	Well Density
173-2025	White Rock Oil & Gas, LLC		Temp. Spacing
174-2025	White Rock Oil & Gas, LLC		Temp. Spacing
175-2025	White Rock Oil & Gas, LLC		Temp. Spacing
183-2025	Phoenix Operating LLC		Spacing
184-2025	Phoenix Operating LLC		Pooling
192-2025	Slawson Exploration Company Inc		Temp. Spacing; Vacate Order
193-2025	Slawson Exploration Company Inc		Well Density
130-2025	Continental Resources Inc		Temp. Spacing; Vacate Order
131-2025	Continental Resources Inc		Well Density
142-2025	MorningStar Operating LLC		Temp. Spacing
202-2025	Black Gold Energy Resource Development, LLC		Change of Operator
203-2025	West Shore Energy LLC		Change of Operator

207-2025	Bad Water Disposal, LLC		Show-Cause
208-2025	Bad Water Disposal, LLC		Show-Cause
209-2025	Big Sky Energy, LLC		Show-Cause
210-2025	Big Sky Energy, LLC		Show-Cause
211-2025	D90 Energy, LLC		Show-Cause
212-2025	D90 Energy, LLC		Show-Cause
214-2025	Enneberg Energy, Inc.	Dismissed	Show-Cause
215-2025	McOil Montana One LLC		Show-Cause
217-2025	XOIL Inc.		Show-Cause
218-2025	Montana Energy Company, LLC		Show-Cause
90-2025	Montana Energy Company, LLC		Show-Cause
92-2025	Yellowstone Petroleums, Inc.		Show-Cause

DEFAULT DOCKET, 6/12/2025

Docket	Applicant	Status	Request
204-2025	White Rock Oil & Gas, LLC		Class II Permit
205-2025	White Rock Oil & Gas, LLC		Class II Permit

EXHIBIT 11

GAS FLARING

June 11, 2025

Flaring Requests

Summary

Both Hilands and OneOK have been recently experiencing pipeline and capacity issues. They are working to resolve the pipeline issues and upgrade compressor capacity. Due to these issues, many wells connected to pipeline are having to flare more than they typically do.

Petro-Hunt

Borntrager 2C-2-1 – API #25-021-21193, 19N-54E-2

1. Flaring 116 MCF/D.
2. Completed: 9/2012.
3. Proximity to market: >25 miles pipeline.
4. Estimated gas price at market: ~$2/MCF.
5. Estimated cost of marketing the gas: ~$3.2 million.
6. Flaring alternatives: Talked to Crusoe about utilizing gas for mobile bitcoin mining operations but need 300 mcf/day to meet minimum requirements.
7. Amount of gas used in lease operations: 7 MCF/D.
8. Justification to flare: Uneconomic to connect due to lack of infrastructure in the area.

Walter Senner 19-54 – API #25-021-21192, 19N-54E-18

1. Flaring 120 MCF/D.
2. Completed: 8/2012.
3. Proximity to market: >25 miles pipeline.
4. Estimated gas price at market: ~$2/MCF.
5. Estimated cost of marketing the gas: ~$3.2 million.
6. Flaring alternatives: Talked to Crusoe about utilizing gas for mobile bitcoin mining operations but need 300 mcf/day to meet minimum requirements.
7. Amount of gas used in lease operations: 7 MCF/D.
8. Justification to flare: Uneconomic to connect due to lack of infrastructure in the area.

Boje Farms 19-54 – API #25-021-21184, 19N-54E-17

1. Flaring 48 MCF/D.
2. Completed: 2/2011.
3. Proximity to market: >25 miles pipeline.
4. Estimated gas price at market: ~$2/MCF.
5. Estimated cost of marketing the gas: ~$3.2 million.
6. Flaring alternatives: Talked to Crusoe about utilizing gas for mobile bitcoin mining operations but need 300 mcf/day to meet minimum requirements.
7. Amount of gas used in lease operations: 7 MCF/D.
8. Justification to flare: Uneconomic to connect due to lack of infrastructure in the area

White Rock

BR 31-31H 37 - API 25-083-22392, 23N-57E-31

1. Flaring amount MCF/day: 185 MCPD
2. Completion date: Refrac date 10/07/2024
3. Estimated gas reserves: 500 MMCF
4. Proximity to market: Currently connected.
5. Flaring alternatives: Only option would be to shut in the well.
6. Amount of gas used in lease operations: 0.4 MCF/D.
7. Justification to flare: The well is connected to the gas sales pipeline, but currently there are no sales as ONEOK, Inc's line pressure and compressor issues have limited White Rock's ability to sale gas.

Nevins Trust 41X-24 - API 25-083-22080, 23N-56E-24

1. Flaring amount MCF/day: 150 MCPD
2. Completion date: Refrac date 09/05/2024
3. Estimated gas reserves: 700 MMCF
4. Proximity to market: Currently connected.
5. Flaring alternatives: Only option would be to shut in the well.
6. Amount of gas used in lease operations: 0.4 MCF/D.
7. Justification to flare: The well is connected to the gas sales pipeline, but currently there are no sales as ONEOK, Inc's line pressure and compressor issues have limited White Rock's ability to sale gas.

Nevins 24X-12 - API 25-083-23476, 23N-56E-12

1. Flaring amount MCF/day: 150 MCPD
2. Completion date: 10/02/2024
3. Estimated gas reserves: 640 MMCF
4. Proximity to market: Currently connected.
5. Flaring alternatives: Only option would be to shut in the well.
6. Amount of gas used in lease operations: 0.4 MCF/D.
7. Justification to flare: The well is connected to the gas sales pipeline, but currently there are no sales as ONEOK, Inc's line pressure and compressor issues have limited White Rock's ability to sale gas.

Prewitt 41X-28 - API 25-083-23477, 22N-59E-28

1. Flaring amount MCF/day: 150 MCPD
2. Completion date: 10/26/2024
3. Estimated gas reserves: 975 MMCF
4. Proximity to market: Currently connected.
5. Flaring alternatives: Only option would be to shut in the well.
6. Amount of gas used in lease operations: 0.4 MCF/D.
7. Justification to flare: The well is connected to the gas sales pipeline, but currently there are no sales as ONEOK, Inc's line pressure and compressor issues have limited White Rock's ability to sale gas.

EXHIBIT 12

Inactive Wells 6/11/2025 Current Actions

Company Name	Total Wells SI	Status	Wells Intended for plugging 2025	Actions	Recommendations
Reserve Operating	1	0 Producing	1	Response received via email with P&A plan. Approved P&A plan on 3/15/2024.	No contact on when plugging will start. Monitor thru 1st Qtr 2025. Letter sent asking for timeline to plug June 10, 2025.
Big Snowy Resources	7	0 Producing	0	1 intent to plug back and convert to water well, 1 intent to plug back and test zone. Ricky 14-1 Sundry Received 10/8/2024 for testing of well.	Fulfilled Admin Order 13-A-2024 with attached letter. Monitor activity thru 2025.
Pinnacle Ranch	1	0 Producing	0	Phone call on 2/8/2024 with operator with potential to turn well into disposal.	Monitor thru 3rd Qtr 2025.
Coalridge Disposal and Petroleum, Inc & Lustre Saltwater Disposal, Vernon R. Justice	4	0/1 Producing 0/2 Injecting	0	Under review with lawyers of proper ownership between family members.	Bonds: T1 $7,000 in 1998; T2 $7,000, B1 $10,000. Monitor situation.
R & A Oil	13	1/14 Producing 0/1 Injecting	0	Letter Received July 1, 2024 from operator with tax information.	2nd letter sent 6/4/2024 response received 7/1/2024. Monitor thru 2025.
Paug, Gerald W	1	0 Producing	0	Inactive Letter Sent November 1, 2024. Signed Return Receipt Received November 6, 2024. Letter received from operator 1/21/2025 asking to turn well into water well within 2 to 6 years.	Monitor thru 2025 and 2026 to see if water right happens
Homestake Oil & Gas Co.	10	100% Fee wells Shut-in. 5/10 wells producing.	0/5	Inactive Letter Sent November 1, 2024. USPS Tracking has letter picked up on November 7, 2024. Email received from operator November 11, 2024. See attached Email.	Monitor thru 2025
Montana Oil and Gas, LLC	6	6/8 Gas wells shut-in	0	Inactive Letter Sent November 1, 2024. Signed Return Receipt Received November 13, 2024.	Monitor thru 2025
BNV Energy Company LLC	2	2 wells shut-in	Unknown	Inactive Letter Sent November 1, 2024. USPS tracking has address vacant. Email notification sent via 2nd letter to last known email address due to vacant physical address 2/11/2025.	Response received 5/7/2025. The two wells in question have been shut in for more than 10 years. See attached response.

Inactive Wells 6/11/2025 Current Actions

Company Name	Total Wells SI	Status	Wells Intended for plugging 2025	Actions	Recommendations
Hesla Oil, LLC	9	0 Producing	Unknown	Sent 2nd letter February 11, 2025. Certified Return Receipt returned to BOGC on February 27, 2025 signed by operator.	No Response by May 8, 2025.
Habets Oil & Gas, LLC	9	0 Producing	Unknown	Sent 2nd letter February 11, 2025. Certified Return Receipt returned to BOGC on February 27, 2025 signed by operator	No Response by May 8, 2025.
D90 Energy LLC	146	146/198 Oil and Gas Wells shut-in	Unknown	Inactive Letter Sent November 6, 2024. USPS tracking moving through Houston, TX facility. Stuck in Houston, TX facility. Notice of filing for bankruptcy on 11/11/2024. Notice of transfer of 54 wells received by BOGC, to be heard at April 2025 hearing.	Monitor D90 Bankruptcy. Staff discussions with Production Energy Partners on ownership of remainder of wells.
Pride Energy Company	5	Wells plugged	Unknown	Sent Inactive Letter Addressing Reclamation on November 1, 2024. USPS Tracking has letter moving thru network on November 16, 2024. No new USPS Update.	2nd Letter sent June 2, 2025. Cert Mail return received by BOGC on June 9, 2025. Response due by July 10, 2025.
XOIL Inc.	2	Wells plugged	0	Response received from operator that they are out of business and won't be reclaiming locations. Administrative Order 1-A-2025 work needs to commence by May 8, 2025. If not $250 fine assessed per day and show-cause ordered for June 12, 2025. See Attached Order.	Operator has indicated no intent to do the work.
Noah Energy, Inc.	5	0/4 Producing 0/1 Injecting	Unknown	Email sent on 8/22/2023. Response received 9/27/2023. Compliance Issues referenced to Billings Office for well identification signs FIXED. Contact with Investor looking to take over wells per inactivity of Noah Energy. No action in 1st Qtr 2025.	Sent second letter May 6, 2025. Response received. See attached.
Cypress Energy Partners - Sheridan SWD, LLC	1	0	Unknown	1 year + of no action since change of operator. Send letter for compliance issue and inacitivity of well. New operator has not bonded the well.	Letter sent 4/9/2025

Total # of Wells **222**

Total Wells April 2025 Meeting 222

Operators under Show Cause 2025				
CoName	**Total Wells SI**		**Actions**	
Yellowstone Petroleums Inc	32	6/38 Producing or Injecting	Update from Shelby Field office 3 wells producing in Brady Field and SWD activated. 2 wells pumping in Kevin-Sunburst Field. Increased shut in wells since 2/28/2023 where 27/38 were shut-in.	See attached Email for update. Update to be given at October 9th, 2024 business meeting per Order 48-2024 and Admininistrative Order 12-2024A. No Activity known as of 12/4/2024. Under Board Order 75-2025. See Attached.

Inactive Wells Bond Forfeited 2022-2025

CoName	Total Wells	Bond Forfeited Date of Board Order	
Powder River Gas, LLC	3	4/14/2022	Bond forfeited, wells plugged.
Janssen Gas	2	4/14/2022	Bond forfeited, wells plugged.
Powers Energy Inc.	1	4/14/2022	Bond forfeited, well plugged.
Forward Energy, LLC	3	4/14/2022	Bond forfeited, 3 wells plugged
Butler Petroleum LLC	1	10/13/2022	Bond forfeited, Well picked up by Poplar Resources in 2023.
Seymour, James & Lorraine	1	12/8/2022	Bond forfeited, well plugged.
Mystique Resources Company	1	4/13/2023	Bond forfeited, well plugged.
Brandon Oil Company	2	8/10/2023	Bond forfeited, Wells plugged.
Bootstrap Oil, LLC	3	8/15/2024	Bond forfeited, waiting to plug in 2025. Contract out for signature to plug.
Summit Gas Resources Inc.	135	2/20/2025	Bond forfeited, remain on orphan well list. Assess time to plan to plug
Total Wells	**152**		

BNV Energy Company LLC
5850 San Felipe St, Suite 500 #1024
Houston, TX 77057

Dear Board of Oil and Gas Conservation:

Thank you for the letter dated February 11th 2025. This letter is to confirm that the following two wells have potential for future use. As such we are requesting inapplicability of the plugging requirement.

049-21110 BNV Eagle 1, 18N-5W-14 NENE, 1005 FNL 1163 FEL, GAS

049-21109 Milford Colony 13-11, 18N-5W-11 SWSW, 1262FSL 213 FWL, OIL

BNV Eagle 1: This well has potential future re-entry and up-hole perforation use.

- The well is currently cased to 3127.83 feet with 4.5" Casing
- Exploration efforts include perforations from 3004" to 3060" though the oil interval was found after a number of efforts including acid stimulation to be heavy and not free-flowing.
- 18N-5W Sec 13 ALL, Sec 14 ALL and Sec15 ALL are leased through Oct 23rd, 2028
- Further up-hole exploration opportunity exists including from approximately 2400' to 2600' where elevated mud gas and lost circulation were noted in the mud logs.

At ~ 2,400' MD gas levels began to rise and eventually heavier gases (C-3 & C-4) began to be displayed by the chromatograph. Gas levels as high as 370 units through a 9.1 ppg mud were recorded. At ~2,545' MD circulation was lost. The rig crew began pumping lost circulation material (LCM) to regain circulation. This caused a loss of samples and gas between 2,545' and 2,589' (Figure 7)

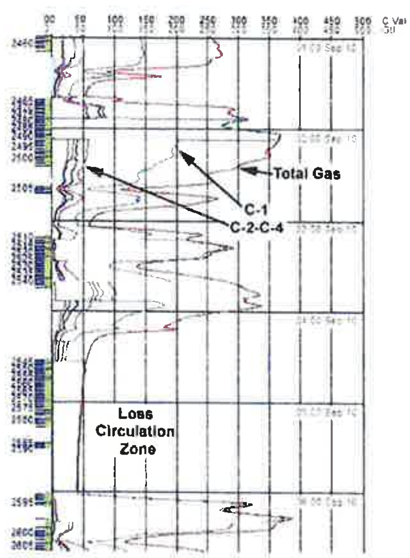


Figure 7: Screen capture of gas near loss circulation zone

Milford Colony 13-11: This well has potential future deepening use.

- The well currently is cased to approximately 850 feet with 9 5/8" casing
- 18N-5W Sec 10 S2, Sec 11 S2 and Sec12 S2 are leased through Oct 23rd, 2028
- Deepening with 8 ¾" hole size to set 7" casing would access the following:

GL (from Survey):	**4216**
SUB:	**10**
KB: (est)	**4226**

LOGS:

PRIMARY TARGET: **BAKKEN**

Formation	Estimated Depth (')	Datum
TWO MEDICINE	SURFACE	
VIRGELLE	127	(+2919)
MILK RIVER	THRUSTED?	
BLACKLEAF	THRUSTED?	
KOOTENAI	THRUSTED?	
MORRISON	THRUSTED?	
SWIFT	THRUSTED?	
RIERDON	6400	(-2185)
SAWTOOTH	7510	(-3295)
MADISON	7580	(-3365)
BAKKEN	8800	(-4585)

BAKKEN HZ TARGET	**OIL**

Thank you for your consideration,

BW Ch

Ben Chu

President, BNV Energy Company LLC

776	A			Wells	SI	%
BNV Energy Company LLC			/ Well	2	2	100%
G2	Single Well Bond	$10,000	$10,000.00	1	1	100%
G1	Single Well Bond	$5,000	$5,000.00	1	1	100%

SI Two to Five Years	SI Five to Ten Years	SI Greater than Ten Years	Total
0	0	2	2

776/G1 Single Well Bond *Last Non-Zero*

776 G1	049-21110	BNV Eagle 1	18N-5W-14	NE NE	1005 FNL, 1163 FEL	C	GAS	--------

776/G2 Single Well Bond *Last Non-Zero*

776 G2	049-21109	Milford Colony 13-11	18N-5W-11	SW SW	1262 FSL, 213 FWL	SP	OIL	--------

1 Operator(s) Included in Report

RECEIVED

MAY 28 2025

MONTANA BOARD OF OIL &
GAS CONSERVATION • BILLINGS

Montana Prospect

Mr. Ben Davis,

Below you will see what work and where Noah Energy stands on each of the wells purchased from Primary Petroleum. All the wells showed commercial economics throughout the clean-up work and production testing. Noah is actively seeking financial assistance in completing the production facilities.

There are four wells that Noah Energy, Inc, Montana purchased from Primary Petroleum Company, USA.

Three of these wells are horizontal wells; One well is a vertical Madison formation well.

All the wells are located in Teton County, Montana within a three mile radius.

All the wells were drilled beginning at the end of the calendar year of 2011; throughout all of 2012, and finished in 2013. A total of eleven wells were drilled. Of the eleven wells, four were completed throughout 2012 and into 2013. The three horizontal wells were all fraced and the vertical well was perforated for testing and production. By February of 2013, Primary Petroleum made the decision to discontinue operations as the wells were not going to produce in the 500 to 2000 barrel per day range; as was their hopes. They speculated that the Bakken formation may have generated large production wells in this area comparable to the wells in North Dakota.

I purchased all interest (87.5% NRI), equipment, additional casing and production tubing, N-80 tubing work string (8,200') and all contracts involved with the four wells in February of 2017.

(a) API #25-099-21316

Spring Hill 14-34-27-6HZ Well

T27N, R6W, Sec.34 SE¼SW¼

331' FSL & 1,980' FWL

Private

This horizontal well was drilled and completed in the Lodgepole formation at a cost of +/- 3.5 million dollars. These wells were left sitting from the time that Primary walked-away in 2013 until Noah Energy purchased them in 2017. In the fall of 2018 Noah Energy began the work to clean-out the wells. Primary walked-away before we had recovered the frac load on any of the three horizontal wells. All three of the horizontal wells have some amount of the frac load still in the well. In the fall of 2018, Noah Energy brought-in rig and crews and did a large acid job followed by the use of a "hydro-scraper" for perforation clean-out and a foaming unit to circulate with little to no hydrostatic pressure. After finishing the clean-up, swabbing results indicated production rates at +/- 40 to 50 barrels per day (approximately %60 of swab rate). The problem currently on this well is an excessive amount of gas creating a gas locking problem. An additional problem with this well was the reaction of the frac fluid with the oil. After the completion of this well, it was determined that the wrong "breaker" within the frac design had been used. This has resulted in problems pumping the oil out of the well at what would be called the "oil/water interface". Due to the "unbroken" frac fluid and the oil composition itself, this fluid is extremely thick and somewhat sticky. It could be referred to as "black honey". I designed and had a tool built to run to the bottom of the hole and capture the fluid rather than attempt to pump it out of the hole. (The well will not support the hydrostatic pressure in addition to the pump pressure. Bottom hole pressure has been determined to be approximately 1500-psi.) This tool was utilized in November of 2023. After making the trip to bottom, 200+ of thick, heavy oil/water was recovered from the tubing. The total volume of oil recovered to date from this well is in excess of 400-barrels. Tubing and pump were run back into the wellbore and the well was pumped for two (2) days at two to two and one half strokes per minute. 70-barrels of oil were produced each of the two days. Thick oil/water again found its way up to the pump. This oil/water combination prevents the balls in the pump from re-seating. A second cleanout run will need be run to capture the remaining thick fluid. All the production facilities are in place on this well. (320-pumping unit; 6 x 20 treater, 4-production tanks and a 275 kw generator to provide the power

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API #25-099-21321

(b) Spring Hill 13-34-27-6 Well

T27N, R6W, Sec.34 SW¼SW¼

330' FSL & 660' FWL

Private

This is a vertical "Madison" formation well. An acid job in conjunction with the "hydro-scraper" was used for perforation clean-up in the fall of 2020. Noah has purchased four 400-barrel production tanks, a 6 x 20 treater, 100' of four inch production line as well as 6,000' of additional 2.375" tubing. All of this equipment was purchased in the last year and is in "nearly new" condition. I will need to purchase a 160 series-pump jack and install the electric line from the Springhill 14-34 horizontal well 1200 feet to the vertical Madison well. I will also run this unit off the 275kw generator currently spotted on the Springhill 14-34 location. Noah has already purchased the "armored" 480 volt electrical wire needed to run this unit and facilities.

Madison wells make water. We were not able to swab this well below 850' at any swab rate. The oil cut remained at 20% throughout two to three days of swabbing. The tubing, pump and rods are in the well and ready for facilities. There is currently a 2" tubing pump installed downhole for greater volume of fluid. Primary Petroleum had invested in this well approximately 1.8 million dollars. Four 400-barrel tanks and a 6 x 20 heater/treater have been purchased for this well. The equipment is currently stored in Sidney, Montana. A 160 pumping unit will be required for this well

(c) API #25-099-21315

Rockport 16-19-27-6HZ Well

T27N, R6W Sec. 19 SE¼SE¼

340' FSL & 661' FEL

Private

This was the third well that Noah Energy worked-over in the fall of 2020. This is a horizontal well in the Potlatch formation. An acid job along with the "hydro-scraper" was utilized on this well also. This well could be the sleeper of the three wells that Noah has ready for production. After the work-over operations, this well continually attempted to flow. We were required to "kill" the well several times in order to complete the downhole work. At one point with the well shut-in for approximately one hour, the surface pressure had built to an excess of 400-psi with a full column of fluid (9.1 #/gal water mix) on both the backside and the tubing side of the well. Noah Energy has purchased for this location and work has begun; 4-400-barrel production tanks; 6 x 20 treater; paid for the rural electric company to drop a transformer for 480-three phase power. Noah will need to purchase a 160 pumping unit, and complete the electrical facilities for the entire pad. I have purchased the armored wire to run power from the pole to the electrical boxes necessary. Primary petroleum had invested in this well a total of 3.2 million dollars. The tubing, rods and pump are installed and waiting for production. Swab rates (conservatively) at 40 to 50 barrels per day.

(d) API #25-099-21320

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Rockport 14-19-27-6HZ Well

T27N, R6W Sec. 19, SE¼SW¼

330' FSL & 2,050' FWL

Private

I have yet to do any clean-out work on this well. This is a Nisku horizontal well. This well would require tubing, rods, pump, and all surface facilities as well as a clean-out and acid job.

Noah Energy has ownership of a 275kw tri-fuel generator and it currently is in use on the Springhill 14-34 location. Noah Energy has purchased 1500' of armored 3-phase, 480 volt electrical wire to run from the Springhill 14-34 to the Springhill 13-34 location, thus eliminating the need for rural electric power. Noah Energy also has purchased four additional 400-barrel, coated, cone bottom tanks and a 6 x 20 heater/treater for the vertical Madison well. The equipment is currently stored in Sidney, Montana. in addition to tubing, rods, miscellaneous pipe and fittings. Two 400-barrel production tanks are in storage in Cutbank, Montana that also belong to Noah Energy. Noah Energy has 4-400 barrel production tanks ready to be spotted in place on the Rockport 16-19 location as well as a 6 x 20 heater/treater. Approximately 40% of the plumbing has been completed and power has been "dropped" from the rural electric company from the pole to the first set of control boxes. The power line and second control set of boxes and breakers have been run and installed to the treater panel. The breakers and control panel at the pumping unit will also need to be installed along with the electrical boxes and work to install the lines.

Noah Energy, Inc. Montana

Bill Paddock

B. Paddock

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Shut-In Wells by Operator

6/10/2025
9:34:28 AM

					Wells	SI	%
830	A						
Noah Energy, Inc.				/ Well	5	4	80%

T1	UIC Single Well Bond	$5,000	$5,000.00	1	1	100%
M1	Multiple Well Bond	$50,000	$12,500.00	4	3	75%

SI Two to Five Years	SI Five to Ten Years	SI Greater than Ten Years	Total
0	0	4	4

830/M1 Multiple Well Bond — *Last Non-Zero*

830 M1	099-21320	Rockport 14-19-27-6HZ	27N-6W-19	SE SW	330 FSL, 2050 FWL	SI	OIL	--------
830 M1	099-21315	Rockport 16-19-27-6HZ	27N-6W-19	SE SE	340 FSL, 661 FEL	SI	OIL	--------
830 M1	099-21321	Spring Hill 13-34-27-6	27N-6W-34	SW SW	330 FSL, 660 FWL	SI	OIL	--------

830/T1 UIC Single Well Bond — *Last Non-Zero*

830 T1	099-21300	Bynum North 7-34	27N-6W-34	SW NE	1660 FNL, 1660 FEL	PI	OIL	--------

1 Operator(s) Included in Report

EXHIBIT 13

BEFORE THE BOARD OF OIL AND GAS CONSERVATION
OF THE STATE OF MONTANA

IN THE MATTER OF HESLA OIL, LLC INACTIVE WELLS IN TOOLE COUNTY, MONTANA.

ADMINISTRATIVE ORDER 7-A-2025

Hesla Oil, LLC (Helsa) is the bonded operator of nine producing wells in Toole County, Montana. These wells have been inactive for two or more years.

On November 1, 2024, a certified letter was mailed to Helsa requesting a plan and schedule of abandonment for the inactive wells or justification with supporting documentation for leaving the inactive wells unplugged. This request was made in accordance with ARM 36.22.1307. No response was received.

On February 11, 2025, a follow up certified letter was sent. This letter was signed by the operator on February 27, 2025. As of the June 11, 2025, business meeting, no response has been received.

IT IS THEREFORE ORDERED by the Board that Helsa must submit its plans and timeline for its inactive wells in Toole County, Montana by July 10, 2025, hearing application deadline.

Dated this 11th day of June, 2025

Montana Board of Oil and Gas Conservation

____

Benjamin Jones, Administrator

BEFORE THE BOARD OF OIL AND GAS CONSERVATION
OF THE STATE OF MONTANA

IN THE MATTER OF HABETS OIL & GAS, LLC INACTIVE WELLS IN TOOLE COUNTY, MONTANA.

ADMINISTRATIVE ORDER 8-A-2025

Habets Oil & Gas, LLC (Habets) is the bonded operator of nine producing wells in Toole County, Montana. These wells have been inactive for two or more years.

On November 1, 2024, a certified letter was mailed to Habets requesting a plan and schedule of abandonment for the inactive wells or justification with supporting documentation for leaving the inactive wells unplugged. This request was made in accordance with ARM 36.22.1307. No response was received.

On February 11, 2025, a follow up certified letter was sent. This letter was signed by the operator on February 27, 2025. As of the June 11, 2025, business meeting, no response has been received.

IT IS THEREFORE ORDERED by the Board that Habets must submit its plans and timeline for its inactive wells in Toole County, Montana by July 10, 2025, hearing application deadline.

Dated this 11th day of June, 2025

Montana Board of Oil and Gas Conservation

Benjamin Jones, Administrator

EXHIBIT 14

June 10, 2025

SUMMARY PAGE

- **Permitting Activity**
  - New Horizontal Locations approved.
    - White Rock Oil & Gas, LLC→ 3 in Richland County
    - MorningStar Operating LLC→ 2 in Richland County
    - Heritage Energy Operating LLC→ 1 in Richland County
  - Vertical APDs Locations approved
    - Coyote Resource LLC → 2 in Toole County
    - Phoenix Operating LLC → 1 SWD in Roosevelt County
  - Re-Issued
    - 6 Wells
      - 1 in Carbon County by Baldwin Lynch Energy Corp.
      - 1 in Liberty County by Avanti Helium US, Inc.
      - 1 in Musselshell County by HC Resources, LLC.
      - 3 in Richland County by Continental Resources Inc.
  - Pending APDs
    - 30 total APDs
      - 2 SWD APDs
      - 28 Horizontal APDs in Richland and Roosevelt Counties.

MONTANA DEPARTMENT OF NATURAL RESOURCES AND CONSERVATION

BOARD OF OIL AND GAS CONSERVATION

2535 St. Johns Avenue, Billings, MT 59102 (406) 656-0040

ACTIVITIES: **4/11/2025 To 6/10/2025**

New Locations:

Roosevelt Wildcat 085-22087
Phoenix Operating LLC Samurai 1 SWD
SHL: NW NW 4-28N-58E (450 FNL/1070 FWL) EL 2110' GR 33032
Proposed Depth: 5586' (Inyan Kara Group)
Approved: 04/24/2025

Toole Wildcat 101-24689
Coyote Resources LLC ig Rose Colony Glacier Ridge 1-28
SHL: SW NW 28-34N-1W (2440 FNL/990 FWL) EL 3558' GR 33034
Proposed Depth: 3200' (Duperow)
Approved: 04/29/2025

Toole Wildcat 101-24690
Coyote Resources LLC William Rodgers Willow Flats 1-19
SHL: SW SE 19-34N-1W (990 FSL/1650 FEL) EL 3535' GR 33038
Proposed Depth: 3200' (Duperow)
Approved: 05/14/2025

New Locations - Horizontal Wells:

Richland Wildcat 083-23495
White Rock Oil & Gas, LLC Putnam 42X-13
SHL: SE NE 13-23N-56E (2300 FNL/697 FEL) EL 2669' GR 33025
PBHL: 21270' SE NE 17-23N-57E (2640 FNL/200 FEL) Bakken
Approved: 04/08/2025

Richland Wildcat 083-23496
MorningStar Operating LLC Roman Roy 31-30-1H
SHL: SE SE 31-26N-53E (285 FSL/587 FEL) EL 2216' GR 33031
PBHL: 18922' NE NE 30-26N-53E (200 FNL/675 FEL) Bakken
Approved: 04/21/2025

ACTIVITIES: **4/11/2025 To 6/10/2025**

New Locations - Horizontal Wells:

Richland Wildcat 083-23497
Heritage Energy Operating, LLC State 15-10-3 1H
SHL: SW SE 15-25N-56E (565 FSL/1960 FEL) EL 2250' GR 33035
PBHL: 25839' NW NE 3-25N-56E (200 FNL/1980 FEL) Bakken
Approved: 05/02/2025

Richland Wildcat 083-23498
White Rock Oil & Gas, LLC Strand Switch 31X-34
SHL: NW NE 34-25N-54E (352 FNL/1921 FEL) EL 2370' GR 33036
PBHL: 21380' SW SW 27-25N-54E (200 FSL/524 FWL) Bakken
Approved: 05/05/2025

Richland Wildcat 083-23499
White Rock Oil & Gas, LLC Candee 21X-6
SHL: NW NE 6-24N-53E (459 FNL/2623 FEL) EL 2422' GR 33037
PBHL: 24954' NE NW 23-25N-52E (200 FNL/2013 FWL) Bakken
Approved: 05/14/2025

Richland Wildcat 083-23500
MorningStar Operating LLC Logan Roy 7-6-1H
SHL: SE SE 7-23N-57E (310 FSL/320 FEL) EL 2487' GR 33039
PBHL: 20361' NW NW 5-23N-57E (200 FNL/240 FWL) Bakken
Approved: 05/20/2025

Re-Issued Locations:

Carbon Wildcat 009-21303
Baldwin Lynch Energy Corp. State 16-33
SHL: NW SE 16-9S-22E (2370 FSL/1840 FEL) EL 4230' GR 32995
Proposed Depth: 8925' (Lakota)
Approved: 04/18/2025

Liberty Wildcat 051-21847
Avanti Helium US, Inc. Keith 14-13
SHL: SE SW 13-36N-6E (706 FSL/1375 FWL) EL 3453' GR 33033
Proposed Depth: 6331' (Flathead Formation)
Approved: 04/25/2025

ACTIVITIES: **4/11/2025 To 6/10/2025**

Re-Issued Locations:

Musselshell Wildcat 065-21898
HC Resources, LLC Lida Kluzek 3
SHL: NE NW 20-11N-28E (660 FNL/1980 FWL) EL 3229' GR 33026
Proposed Depth: 3250' (Piper Formation)
Approved: 04/15/2025

Richland Wildcat 083-23288
Continental Resources Inc Bahls HSL
SHL: NE NE 10-23N-56E (345 FNL/330 FEL) EL 2505' GR 33027
PBHL: 20281' SE SE 15-23N-56E (200 FSL/0 FEL) Bakken
Approved: 04/18/2025

Richland Wildcat 083-23301
Continental Resources Inc Slocum 3-8H
SHL: NE NW 8-26N-53E (230 FNL/1343 FWL) EL 2281' GR 33028
PBHL: 19138' SE SW 17-26N-53E (200 FSL/1980 FWL) Bakken
Approved: 04/18/2025

Richland Wildcat 083-23302
Continental Resources Inc Slocum 2-8H
SHL: NW NW 8-26N-53E (230 FNL/1298 FWL) EL 2282' GR 33029
PBHL: 19132' SW SW 17-26N-53E (200 FSL/660 FWL) Bakken
Approved: 04/18/2025

Completions:

Richland Wildcat 083-23463
Kraken Operating, LLC Meldahl LW 20-29-32 1H
SHL: SE SW 17-26N-59E (540 FSL/1936 FWL) EL 2001' GR
BHL: 25415' SE SE 31-26N-59E (979 FSL/16 FEL) Bakken
Completed 7/10/2024 (OIL). TD 25415'
IP 1317 BOPD/659 MCFPD/2066 BWPD Bakken

Richland Wildcat 083-23464
Kraken Operating, LLC Meldahl 20-29-32 2H
SHL: SE SW 17-26N-59E (540 FSL/1969 FWL) EL 2001' GR
BHL: 25385' SE SW 32-26N-59E (982 FSL/2009 FWL) Bakken
Completed 7/8/2024 (OIL). TD 25385'
IP 1102 BOPD/768 MCFPD/2143 BWPD Bakken