Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

Matthew H. Mead, Governor

Todd Parfitt, Director

October 31, 2014

COMMENT RESPONSE CONCERNING THE PROPOSED WYOMING AIR QUALITY STANDARDS AND REGULATIONS, CHAPTER 8, SECTION 6, NONATTAINMENT AREA REGULATIONS

The Air Quality Division is taking this opportunity to respond to all comments officially submitted prior to the close of the Air Quality Advisory Board meeting on July 14, 2014.

INTRODUCTION

On July 14, 2014 the Air Quality Advisory Board (Board) met in Rock Springs, Wyoming. The Air Quality Division (Division) requested the Board's consideration on proposed changes to Wyoming Air Quality Standards and Regulations (WAQSR), Chapter 8, Nonattainment Area Regulations. Chapter 8, Section 6, Requirements for existing oil and gas production facilities or sources in the Upper Green River Basin, was proposed to establish requirements for existing oil and gas production facilities located in the Upper Green River Basin (UGRB) ozone nonattainment area. As indicated in the June 13, 2014 Public Notice, the public was given 30 days to comment on the proposed WAQSR, Nonattainment Area Regulations. The official comments, both verbal and written, were accepted through the end of the July 14, 2014 Board meeting.

During the July 14, 2014 meeting, the Board considered comment requesting that a recommendation on the existing source regulation be stayed until the Division met with interested parties to discuss comment. The Division held a July 31, 2014 meeting with all interested stakeholders to try to address comments. The Board met again on August 4, 2014 via conference call and voted to defer consideration of this regulation to a future Board meeting. The Division hosted several public meetings with individual stakeholder groups to discuss and clarify comments received during the public comment period held prior to the July 14, 2014 Board meeting.

The Division has the responsibility, and continues to work diligently, to keep this rulemaking process moving forward. This unique opportunity to address emissions from existing sources in the UGRB allows Wyoming to stay at the forefront of sensible oil and gas air regulations.

OVERVIEW OF COMMENTS RECEIVED

During the 30-day comment period, including the Board meeting, the Division received six (6) individual comment letters. Comments were received from a federal agency, industrial proponents, and environmental advocacy groups.

PROCESS FOR TRACKING PUBLIC COMMENTS

Official comments on the existing source regulation were divided into groups by commenter type; federal agencies, industrial proponents, and environmental advocacy groups. The Division analyzed each letter and verbal comment to identify potentially substantive comments. Within each commenter group the letters and verbal comments containing substantive comments requiring a response from the Division were given an identifying number (e.g. federal agency letter 1 is coded FA-1, industrial proponent letter 1 is coded P-1, industrial proponent 2 verbal comment is P-2V).

CONTENT ANALYSIS ANNOTATION

The Content Analysis process was used to identify substantial comments that may require a response from the Division. Substantial comments are identified electronically on the original correspondence or written transcript from the Board meeting, along with their unique identifier by highlighting individual comments. The letter/written transcript identifier and comment number are annotated in the left or right hand margins of the correspondence. Official comment letters, annotated by the Division, are located in Attachment A of this document.

All official comments received are included under specific headings such as; General Comments, Compliance Time Frame, or Sections of the Proposed Regulation. Many uniquely identified comments have been grouped together by topic with the Division's overarching response following.

OFFICIAL COMMENT LOG

Unique Identifying Number	Date Received	Agency, Organization or Individual
FA-1	7/11/14	U.S. Environmental Protection Agency – Region 8
EG-1	7/11/14	Joint Letter - Environmental Defense Fund and Wyoming Outdoor Council
EG-2	7/14/14	Wyoming Outdoor Council – Bruce Pendrey
P-1	7/11/14	Anadarko Petroleum Corporation

Unique Identifying Number	Date Received	Agency, Organization or Individual
P-2	7/11/14	Petroleum Association of Wyoming
P-2V	7/14/14	Verbal Comment – Petroleum Association of Wyoming
P-3	7/11/14	USQ – Ultra, Shell and QEP
End of Comment Period (7/14/14)		
*	7/19/14	Dave Hohl

* This comment was not assigned a Unique Identifying Number due to the late submittal date. However, most concerns within Mr. Hohl's comment letter are addressed in the Division's response to comment document.

COMMENTS AND RESPONSE

COMPLIANCE TIME FRAME:

Comment Number(s): P-1-3, P-1-13, P-2-10, P-2-16, P-2-21, P-2-23, P-2-37, P-2-45, P-2-46, P-3-1, P-3-7, P-3-17, P-3-22

Response:
Thank you for outlining the hardships of complying with this regulation in the proposed time frame. It is of the utmost importance to work quickly for the benefit of human health in the UGRB. Therefore, extending the compliance time frame within the regulation beyond one (1) or more years is unnecessary due to delays experienced within the rule making process.

GENERAL COMMENTS:

Comment Number (s): P-2V-1

RESPONSE:
The Division organized and hosted a special public meeting to address stakeholder concerns regarding the existing source regulation on July 31, 2014 at the Wyoming State Library in Cheyenne, Wyoming. During the July 31, 2014 meeting, it was requested that additional individual meetings with specific stakeholders occur. The Division went above and beyond the initial request by hosting three (3) additional stakeholder meetings on August 18, August 26, and September 3, 2014.

Comment Number(s): EG-2-5, EG-2-6, P-1-1

RESPONSE:
Thank you for your support of the Division's decision to pursue an emission budget approach. The Division plans to pursue developing this option as promptly as possible.

The Division does not have the resources available, at this time, to conduct a fine grain analysis to provide the anticipated emission reductions. Through the implementation of this regulation, proponents will be required to provide a more refined and detailed summary of specific equipment and associated emission reductions at applicable facilities to get this vital information. It is important to note that as a long term benefit, existing facilities will not be allowed to remove controls at a threshold higher than 4 tons per year (tpy) in the nonattainment area.

The Division understands knowledge of Phase 2 is important to share. At this time we cannot provide information necessary to respond to comment on Phase 2. However, the stakeholder process will be a critical component of developing the Phase 2 emissions budget based control strategy.

Comment Number(s): EG-1-2, EG-2-1

RESPONSE:
This proposed regulation is designed to be no more stringent than requirements for new and modified sources as permitted under the Chapter 6, Section 2, Oil and Gas Guidance (September 2013). The Division finds that a threshold of 4 tpy for existing sources is technically feasible and economically reasonable while not undermining the permitting process.

Comment Number(s): P-1-16, P-2-48, P-3-2, P-3-11

RESPONSE:
This proposed regulation will not eliminate the Chapter 6, Section 2(c)(ii), Interim Permitting Policy for sources in Sublette County (Interim Policy). The Interim Policy is expected to be addressed in the Phase 2 rulemaking.

This proposed regulation does not require a permit for the installation of control devices. However, if a company would like to receive offset credits for controlling VOC emissions, they must receive a New Source Review permit prior to the compliance date in the Upper Green River Basin existing source regulations.

Comment Number(s): EG-1-3, EG-1-4, EG-1-5

RESPONSE:
The Division heard from environmental advocacy groups that including compressor stations in the proposed regulation would be beneficial to the environment and the health of the UGRB citizens. As stated during the July 31, 2014 public meeting, industrial proponents are not opposed to reducing emissions at compressor stations. In response to these comments, implementing a Leak Detection and Repair (LDAR) program will be required for compressor stations under subpart (g) of the Upper Green River Basin existing source regulations, as applicable.

Comment Number(s): EG-1-4, EG-1-10, EG-2-3

RESPONSE:
Currently federal regulation does not require the regulation of Greenhouse Gases, e.g., methane, for minor sources. Wyoming Statute, §35-11-213 prohibits the State of Wyoming from being any more stringent than federal regulation.

Comment Number(s): FA-1-6

RESPONSE:
The Division has reviewed the proposed regulation and revised any provision that could compromise the federal enforceability of the State Implementation Plan (SIP).

Comment Number(s): P-3-3

RESPONSE:
As this regulation is a Permit by Rule, a permit is not needed to address affected existing facilities. The Division intends the Upper Green River Basin existing source regulations to become federally enforceable under a SIP submitted to Environmental Protection Agency (EPA).

PROPOSED REGULATION - APPLICABILITY - SECTION 6 (a):

Comment Number(s): P-2-1, P-3-5

RESPONSE:
The regulation as proposed on July 14, 2014, was limited to single and multiple well pad oil and gas production facilities or sources and equipment on those sites not extending to midstream facilities or sources. Based on comment received, the proposed regulation has been revised to include compressor stations.

Comment Number(s): P-2-3

RESPONSE:
The Division acknowledges this typographical error and has revised the language in the proposed regulation.

Comment Number(s): FA-1-3, P-2-2, P-3-4

RESPONSE:
The procedure used to determine whether a WAQSR Chapter 6, Section 2 permit meets or exceeds the requirements of the proposed regulation will be a line by line comparison of permit conditions completed by the proponent. If a permit is more stringent than the proposed regulation, the permit conditions stand and the affected facility has satisfied the requirements of the proposed regulation. If the permit is less stringent, the facility must comply with all applicable requirements of the proposed regulation. The January 1, 2014 applicability date was chosen to avoid an "applicability gap" between older sources and sources permitted under the Oil and Gas Guidance (September 2013) for new and modified facilities.

Comment Number(s): P-2-4

RESPONSE:
The proposed regulation does not prevent the incentive to do voluntary permitting under the Oil and Gas Guidance (September 2013).

Comment Number(s): P-1-4, P-1-9 P-2-5, P-2-12, P-2-17, P-2-29, P-3-12

RESPONSE:
The wording change of "98% manufacturer designed VOC destruction efficiency" will be used throughout the Upper Green River Basin existing source regulation. Based on discussions during the public meetings the Division has determined that the purposed language meets the intent and purpose of the regulation.

PROPOSED REGULATION -DEFINITIONS – SECTION 6 (b):

Comment Number(s): P-2-6

RESPONSE:
The Division determined it is inappropriate to include in a definition where an extended hydrocarbon analysis sample must be taken. The Division relocated the language to an appropriate subsection within the proposed regulation.

Comment Number(s): P-2-7, P-2-49

RESPONSE:
The Division determined that the absence of the narrative language included in the Oil and Gas Guidance (September 2013) definition of "PAD facility" does not create an inconsistency with the proposed regulation definition.

Comment Number (s): P-1-2, P-2-8, P-2-44

RESPONSE:
The Division will use the Chapter 8, Section 5, Ozone Nonattainment Emission Inventory Rule regulatory language for responsible official to provide clarity and consistency within the WAQSR.

Comment Number(s): P-2-9, P-2-49

RESPONSE:
The Division determined that the absence of the narrative language included in the Oil and Gas Guidance (September 2013) definition of "single well facility" does not create an inconsistency with the proposed regulation definition.

PROPOSED REGULATION - FLASHING EMISSIONS – SECTION 6 (c)(i):

Comment Number(s): FA-1-4

RESPONSE:
The 4 tpy applicability threshold is based on the operating parameters of the emission unit as defined in the proposed regulation. For example, flashing emissions from storage tanks are based on model results using actual operating parameters and production rates.

Comment Number(s): FA-1-1

RESPONSE:
The Division has reviewed the proposed regulation and revised any provision that could compromise the federal enforceability of the SIP.

Comment Number(s): FA-1-5

RESPONSE:
The Division considered EPA's proposed language to be consistent with the intent of the proposed regulation and has revised the language in the appropriate Subsection.

Comment Number(s): EG-1-9, EG-2-2, P-1-5, P-2-11, P-2-47, P-3-10

RESPONSE:
The Division considers the requirement to control produced water tanks to be explicit, as produced water tanks are called out in the definition of "storage tanks".

The proposed regulation is designed to require that emergency, open top, and/or blowdown tanks will not be used as active storage tanks. In order to guarantee these storage tanks are used on a temporary basis, the Division has included the requirement that emergency, open top, and/or blowdown tanks be emptied within seven (7) days. Flashing emissions from storage tanks are important to control to help protect public health in an Ozone Nonattainment Area and therefore this requirement will not be removed from the proposed regulation.

PROPOSED REGULATION –FLASHING EMISSIONS APPLICABILITY– SECTION 6 (c)(ii):

Comment Number(s): P-2-13

RESPONSE:
The utilization of one (1) calendar year in the calculation for flashing emissions is reasonable, as the use of an annual production average will capture a representative sample of normal production operations.

Comment Number(s): P-2-14

RESPONSE:
The regulation allows for a site specific or composite extended analysis. As stated in the definition of composite extended hydrocarbon analysis, the analysis is based on at least five (5) wells producing from the same formation and under similar conditions.

Comment Number(s): P-2-15

RESPONSE:
Reid Vapor Pressure (RVP) of sales oil is provided as part of the hydrocarbon analyses submitted in permit applications, and is a required model input parameter.

PROPOSED REGULATION - DEHYDRATION UNITS– SECTION 6 (d)(i):

Comment Number(s): P-3-13

RESPONSE:
Most combustors are designed to meet the 98% manufacturer designed VOC destruction efficiency. To satisfy the requirement of the proposed regulation, proponents will be required to provide a verification of the manufacturer's designed destruction efficiency level of 98%. If no documentation exists, the affected facility will need to be controlled pursuant to the proposed regulation.

Comment Number(s): EG-1-8

RESPONSE:
The Division acknowledges the more stringent requirements in place for new and modified Jonah and Pinedale Anticline Development (JPAD) area facilities. However, this proposed regulation for existing sources is designed to be no more stringent than requirements for new and modified sources outside of the JPAD area in the UGRB Nonattainment Area. In further support of allowing control removal, it should be noted that the practice is not a common one. The Division has not seen an influx of control removals on dehydration units as allowed under existing permits. Also, industrial proponents operating within the nonattainment area have commented that "it seems rare that dehy controls would be removed." (P-3-21).

PROPOSED REGULATION –DEHYDRATION UNITS APPLICABILITY– SECTION 6 (d)(ii):

Comment Number(s): FA-1-2

RESPONSE:
The Division has reviewed the proposed regulation and revised any provision that could compromise the federal enforceability of the SIP.

Comment Number(s): P-1-6, P-2-18

RESPONSE:
This proposed regulation is a Permit by Rule, all existing facilities and sources in the UGRB will have to meet the control requirements set forth within the proposed regulation unless the facility or source is already satisfying conditions of a Chapter 6, Section 2 permit that meets or exceeds the proposed control requirements. The Division has not allowed the use of flash tanks and/or condensers as the sole means of emissions control for dehydration units. For example, applicability for new and modified sources under the Oil and Gas Guidance has been determined using total uncontrolled emissions; therefore the Division has determined it is not appropriate to utilize flash tanks and condensers in determining applicability in the proposed regulation for existing sources.

Comment Number(s): P-2-19, P-2-42

RESPONSE:
The utilization of one (1) calendar year in the calculation for flashing emissions is reasonable, as the use of an annual production average will capture and represent normal production operations.

Comment Number(s): P-3-14, P-3-15

RESPONSE:
The Division has used the separator pressure for all samples collected for use in permit applications under the Oil and Gas Guidance.

The intent of the proposed regulation is to get the most up to date and accurate data possible in order to calculate emissions for determining which existing facilities would be subject to the proposed regulation based on permit conditions, not Emission Inventory calculations.

PROPOSED REGULATION - EXISTING PNEUMATIC PUMPS– SECTION 6 (e):

Comment Number(s): EG-1-6

RESPONSE:
When possible, proponents in the UGRB are using technologies to eliminate natural gas pneumatic pump emissions. The Division cannot prescribe the type of control used to meet the 98% manufacturer-design control efficiency for facilities or sources in the UGRB.

Comment Number(s): EG-1-7, P-1-7, P-2-20, P-3-18

RESPONSE:
Based on comments, the Division will be removing this language from the proposed regulation.

Comment Number(s): P-3-16

RESPONSE:
No control device would be needed.

PROPOSED REGULATION - EXISTING PNEUMATIC CONTROLLERS – SECTION 6 (f):

Comment Number(s): P-2-22

RESPONSE:
The Division has taken this comment into consideration and has made appropriate changes to meet the intent and purpose of the proposed regulation.

Comment Number(s): EG-1-9

RESPONSE:
The Division considers the requirement to control pneumatic controllers to be explicit, in accordance with Section 6 (f) of the proposed regulation.

PROPOSED REGULATION - FUGITIVES – SECTION 6 (g):

Comment Number(s): P-2-24

RESPONSE:
Subsection (h)(iii)(F) of the proposed regulations refers to the submission of the LDAR protocol prior to implementation of the protocol and is irrelevant to the demonstration of permitting guidance equivalence.

Comment Number(s): P-2-25, P-3-6

RESPONSE:
The requirement to do quarterly inspections is consistent with LDAR requirements outlined in the Oil and Gas Guidance, these requirements and good operating practices will help industry detect and repair a source of fugitive emissions that impact human health in the UGRB Ozone Nonattainment Area.

Comment Number(s): EG-1-1, EG-1-2

RESPONSE:
This proposed regulation is designed to be no more stringent than requirements for new and modified sources as permitted under the Chapter 6, Section 2, Oil and Gas Guidance (September 2013). The Division finds that a threshold of 4 tpy for existing sources is technically feasible and economically reasonable while not undermining the permitting process.

Comment Number(s): P-1-8, P-2-26, P-3-8

RESPONSE:
The Division has taken these comments into consideration and has revised the proposed regulation.

Comment Number(s): P-2-27, P-3-9

RESPONSE:
Oil and Gas Guidance Table 2-4 from EPA-456/R-95-017 as referenced in the proposed regulation, has gone unchanged since 1996 and is widely used. However, if the Emission Inventory Study yields results that could be incorporated into the proposed regulation, the Division may consider the option.

PROPOSED REGULATION - MONITORING – SECTION 6 (h)(i):

Comment Number(s): P-2-28

RESPONSE:
The Division has taken this comment into consideration and has made appropriate changes to clarify the monitoring requirements of the proposed regulation.

Comment Number(s): P-1-9, P-2-29, P-3-19

RESPONSE:
The Division has taken these comments into consideration and has made appropriate changes to clarify the monitoring requirements of the proposed regulation.

Comment Number(s): P-2-30, P-2-32

RESPONSE:
Quarterly site evaluations of control equipment and systems are required. This requirement is not part of the LDAR protocol referenced in Subsection (g). However, an LDAR protocol will satisfy this requirement as specified in the Monitoring, Reporting and Recordkeeping Section.

Comment Number(s): P-1-10, P-2-31

RESPONSE:
The Division has taken these comments into consideration and has revised the proposed regulation by incorporating a leak repair schedule requirement into the proposed regulation.

Comment Number(s): P-3-20

RESPONSE:
The Division has determined that no emission reduction benefit was associated with this requirement, and has removed the language from the proposed regulation.

PROPOSED REGULATION - RECORDKEEPING – SECTION 6 (h)(ii):

Comment Number(s): P-2-33

RESPONSE:
The Division took this comment under consideration and has made appropriate changes in the proposed regulation to acknowledge that design configurations may differ between facilities.

Comment Number(s): P-1-11, P-2-34

RESPONSE:
The Division took these comments under consideration and has not revised the proposed regulation. The Division considers the recordkeeping requirement critical to understand why the monitored parameter is absent, which can help in determining compliance and/or maintenance concerns.

Comment Number(s): P-1-12, P-2-35, P-3-21

RESPONSE:
The Division has determined that no emission reduction benefit was associated with this requirement, and has removed this requirement from the proposed regulation.

Comment Number(s): P-2-36

RESPONSE:
The Division took this comment under consideration and has not revised the proposed regulation. The Division does not consider the recordkeeping requirement duplicative. Recordkeeping associated with blowdown and venting permits only cover the volume of gas and emissions associated with those events, not the liquids handling and storage. Records generated under Chapter 1, Section 5 will satisfy the recordkeeping requirements in the proposed regulation.

PROPOSED REGULATION - REPORTING – SECTION 6 (h)(iii):

Comment Number(s): P-2-37

RESPONSE:
The Division concludes the "will be required" language is applicable. The required notification will be beneficial for Division staff and any future maintenance of the National Ambient Air Quality Standards (NAAQS), or nonattainment area demonstration exercises the Division may be required to conduct.

Comment Number(s): P-1-14, P-1-15, P-2-38, P-2-39, P-2-41

RESPONSE:
The Division has taken these comments into consideration and modified the proposed regulation for clarity on frequency of reporting requirements. The Division considers the proponent reporting requirements essential to keep Division staff informed of where control installations are occurring under the proposed regulation.

Comment Number(s): P-2-40

RESPONSE:
The Division has taken this comment into consideration and has not revised the proposed regulation. The Division considers the proponent reporting requirements essential to keep Division staff informed of the type of pneumatic controller being installed under the proposed regulation.

Comment Number(s): P-2-43

RESPONSE:
The Division took this comment under consideration and removed this language from the proposed regulation.

ATTACHMENT A

- FA-1 (U.S. Environmental Protection Agency – Region 8)
- EG-1 (Environmental Defense Fund and Wyoming Outdoor Council)
- EG-2 (Wyoming Outdoor Council –Bruce Pendrey)
- P-1 (Anadarko Petroleum Corporation)
- P-2 (Petroleum Association of Wyoming)
- P-2V (Verbal Comment – Petroleum Association of Wyoming)
- P-3 (USQ – Ultra, Shell and QEP)

FA-1

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

JUL 2014
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AIR QUALITY
DIVISION

JUL 10 2014

Ref: 8P-AR

Steven A. Dietrich
Administrator, DEQ/AQD
Herschler Building 2-E
122 W. 25th Street
Cheyenne, Wyoming, 82002

RE: EPA Region 8 Comments on Wyoming's Proposed Changes to Wyoming Air Quality Standards and Regulations (WAQSR), Chapter 8, Nonattainment Area Regulations

Dear Mr. Dietrich:

Thank you for the opportunity to provide comments on the state of Wyoming's proposed changes to Wyoming Air Quality Standards and Regulations (WAQSR), Chapter 8, Nonattainment Area Regulations. These changes were proposed for public comment on June 13, 2014, with comments due by the close of the Wyoming Air Quality Advisory Board (Board) meeting on July 14, 2014. These proposed changes address potential requirements for existing oil and gas production facilities or sources in the Upper Green River Basin (UGRB).

In the public notice for the Board meeting the Air Quality Division (AQD) stated they intend to submit these changes to the Environmental Protection Agency (EPA) for incorporation into the State Implementation Plan (SIP). Our comments herein should be considered preliminary, as we will not reach any final conclusions until the state provides a formal submittal of these SIP changes to the EPA and after we conduct our own notice and comment rulemaking.

Based on the assumption that these provisions are submitted to EPA for incorporation into the Wyoming SIP, we have six preliminary comments, which are detailed below.

Comment 1:

FA-1-1

Draft Chapter 8, Section 6, subsection (c) addresses flashing emissions of vapor streams containing VOC or HAP components from all existing storage tanks and all existing separation vessels. Draft subsection (c)(ii)(B), which covers methods to determine the applicable uncontrolled VOC and HAP emissions from these tanks and vessels, states "Use a Division-approved flash emissions model or direct measurement of tank emissions to determine uncontrolled VOC and HAP emissions." This language is a form of director discretion that would undermine the federal enforceability of this provision. We suggest the language be revised to specify specific models, or direct measurement techniques or methods, to determine these emissions.

Comment 2:

FA-1-2

Draft Chapter 8, Section 6, subsection (d) addresses vapor streams containing VOC or HAP components released from all existing dehydration units. Draft subsection (d)(ii)(B), which covers methods to determine the applicable uncontrolled VOC and HAP emissions from these units, states "Use GRI-GLYCalc V4.0 or other methods approved by the Division with the annualized average daily production rate to determine annualized uncontrolled VOC and HAP emissions from the dehydration unit process vents." While the use of "GRI-GLYCalc V4.0" is a specific method, the "other methods approved by the Division" is a form of director discretion that undermines federal enforceability of the SIP (similar to comment 1 above). We suggest the language be revised to specify specific models, or methods, to determine these emissions.

Comment 3:

FA-1-3

Draft Chapter 8, Section 6, subsection (a)(ii) exempts facilities and sources from the regulations if "a Wyoming Air Quality Standards and Regulations (WAQSR) Chapter 6, Section 2 permit has been issued, which mu[st] be as stringent or more stringent than the requirements of these regulations." EPA is unsure of the intent of this subsection. Would it only exempt sources for which the permit was finalized on or before the January 1, 2014 applicability date specified in the provision? If so, the provision should be clarified to state that only sources permitted on before January 1, 2014 are subject to the provision. However, if the intent is to create an open-ended and ongoing exemption (i.e., including permits issued after January 1, 2014), then the language would be a form of director discretion that would undermine the federal enforceability of the existing SIP. Also, it is unclear what procedure would be used to determine whether a particular permit was as stringent as the requirements of the regulations, who would make the determination and how the interested parties would be notified (e.g., permittee and the public). In addition, if AQD intends in the future to rely on emissions reductions from these rules to meet Clean Air Act (CAA) requirements, we suggest AQD consider how existing permits will be taken into account to determine emission reductions.

Comment 4:

FA-1-4

Draft Chapter 8, Section 6, subsections (c)(i)(A), (c)(i)(D), (d)(i)(A), (d)(i)(B), (e)(ii), and (g)(i), all detail applicability levels related to emissions of 4 tons per year (tpy). It is not clear if the 4 tpy level is based on actual emissions or potential to emit. Please clarify this applicability level, so it is clear to the regulated community and the public who would be subject to the requirements.

Comment 5:

FA-1-5

Draft Chapter 8, Section 6, subsection (c)(i)(C)(I) states "Emergency tanks shall be utilized for malfunctions only as allowed in Chapter 1, Section 5 of the WAQSR." We note the Wyoming SIP, Chapter 1, Section 5 does not allow exemptions from compliance with emission limits because of malfunctions. Instead, malfunctions that result in excess emissions are violations of the CAA and the Wyoming SIP. Chapter 1, Section 5 details reporting requirements for excess emissions resulting from malfunctions and indicates AQD's discretion regarding enforcement of these violations. We suggest that the language in subsection (c)(i)(C) be clarified to state that emergency tanks can only be used for unavoidable equipment malfunctions as defined in Chapter 1, Section 5.

FA-1

- FA-1-6 -

Comment 6:

We suggest that Wyoming review the draft rule to determine if there may be other instances of director discretion that could undermine the federal enforceability of the SIP.

We want to acknowledge the proactive efforts of the Wyoming AQD to improve air quality in the UGRB, including these proposed requirements for existing oil and gas production sources. We also want to provide any assistance needed and look forward to working with you to resolve the issues that we have identified. If you have any questions, please contact me at 303-312-6416, or your staff may contact Steven Pratt, Wyoming SIP Coordinator, at 303-312-6575.

Sincerely,

Carl Daly

Carl Daly, Director
Air Program

cc: Jennifer Cederle, WDEQ-AQD

EDF ENVIRONMENTAL DEFENSE FUND
Finding the ways that work

Wyoming Outdoor Council

July 11, 2014

Mr. Steven A. Dietrich
Administrator, DEQ/AQD
Herschler Building 2-E
122 W. 25th Street
Cheyenne, Wyoming, 82002

VIA Regular Mail and Facsimile

Dear Mr. Dietrich:

Thank you for accepting these comments on proposed requirements for existing oil and gas production facilities/sources in the Upper Green River Basin on behalf of the Environmental Defense Fund ("EDF"), the Wyoming Outdoor Council ("WOC") and Citizens United for Responsible Energy Development ("CURED").[1] EDF is a national membership organization with over 750,000 members residing throughout the United States who are deeply concerned about the pollution emitted from oil and natural gas sources. WOC is Wyoming's oldest statewide independent conservation organization and has worked to protect Wyoming's environment and quality of life for future generations for more than forty-five years. CURED is a Pinedale based advocacy group and member of the state's ozone task force.

I. Introduction

We appreciate the Air Quality Division's ("AQD") demonstrated commitment to reducing harmful emissions from oil and gas activities in the Upper Green River Basin ozone nonattainment area ("UGRB NAA" or "Basin"). Strong protections in the UGRB NAA are necessary to restore healthy, clean air to the residents of Sublette, Sweetwater and Lincoln counties. Once home to some of the most pristine air quality in the nation, the area has received failing grades for ozone pollution from the American Lung Association for the past two years.[2]

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[1] *See* proposed revisions to WY DEQ AQD REGS Ch. 8 § 6 (June 6, 2014).
[2] American Lung Association, State of the Air (2013), (2014), http://www.stateoftheair.org.

And, just last year, the Wyoming Dept. of Health documented an increase in clinic visits for adverse respiratory-related effects on particularly smoggy days in Sublette County.[3]

The Wyoming Department of Environmental Quality ("DEQ") has authority to issue robust, comprehensive regulations that minimize the releases from natural gas development due to venting, flaring and fugitive emissions. DEQ has a duty to "prevent, reduce and eliminate pollution" and "preserve, and enhance the air…of Wyoming".[4] To fulfill this obligation, the AQD may establish rules or regulations "as may be necessary to prevent, abate, or control pollution."[5] In recommending such rules or regulations the Director must consider "the character and degree of injury to, or interference with the health and physical well-being of the people, animals, wildlife and plant life" as well as the "technical practicability and economic reasonableness of reducing or eliminating the pollution", as well as other factors.[6]

As the AQD is aware, and as we have expressed in prior comments,[7] the wasteful practice of venting, flaring and leaking natural gas from oil and gas sources contributes to unhealthy air pollution comprised of smog-forming volatile organic compounds ("VOCs"), climate altering methane ("CH4")[8] and carcinogenic hazardous air pollutants ("HAPs"). Existing sources in the UGRB NAA are responsible for a considerable share of these deleterious pollutants. In 2011 14% of the volatile organic compounds ("VOC") and approximately 28% percent of methane ("CH4") emitted from oil and gas activities in the state came from sources in the UGRB.[9] Pneumatic pumps and controllers are the largest source of VOCs, followed by fugitives, and glycol dehydrators in the Basin.[10] Dehydration units are also the largest source of air toxics in the UGRB NAA, responsible for 58% of the HAPs emitted from oil and gas sources.

Historically, Wyoming has demonstrated leadership when it comes to clean air measures for oil and gas activities. Following in this tradition, last year's revision to the permitting guidance for new and modified sources in the Basin provided a blueprint upon which other states and jurisdictions can and do act when promulgating rigorous control requirements for oil and gas

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3 State of Wyoming, Dept. of Health, Associations of Short-term Exposure to Ozone and Respiratory Outpatient Clinic Visits-Sublette County, WY, 2008-2011 (March 1, 2013), file:///Users/Bessie/Downloads/WDHOzoneReport.pdf.

4 WY ENV. QUALITY ACT § 35-11-102.

5 *Id.* at § 35-11-202(a).

6 *Id.* at 202(b).

7 *See* EDF, WOC and CURED Comments to DEQ/AQD re: proposed revisions to its Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance ("P-BACT Guidance") (Sept. 2013).

8 The IPCC recently revised its estimate of the warming potential of methane to indicate that over the short-term (20 years), methane is at least 84 times more effective at trapping heat than carbon dioxide. Over a 100-year period, methane has a warming potential at least 28 times that of carbon dioxide. *Working Group Contribution to the IPCC Fifth Assessment Report Climate Change 2013: the Physical Science Basis, Final Draft Underlying Scientific-Technical Assessment*, Chapter 8, Table 8.7, page 8-58, available at http://www.climatechange2013.org/images/uploads/WGIAR5_WGI-12Doc2b_FinalDraft_Chapter08.pdf.

9 We cite here to the 2011 inventory because the AQD relied on this inventory when developing its proposal. *See* Memorandum to Air Quality Advisory Board from J. Cederle, et al., (July 13, 2014) ("Statement of Basis").

10 *See* 2011 UGRB Inventory, http://deq.state.wy.us/aqd/Actual%20Emissions.asp. We calculated methane emissions by converting the VOC emissions reported to the DEQ to methane using standard EPA VOC to CH4 conversion factors.

activities.[11] Many aspects of the current proposal continue this demonstration of leadership and protectiveness. In particular, we commend DEQ for proposing to require the replacement of both continuous and intermittent high-bleed pneumatic controllers with low or no-bleed ones, 98% control of flash emissions from storage tanks and separation vessels and glycol dehydrators, the elimination or 98% reduction of pneumatic pump emissions, and quarterly instrumented leak inspections at well sites. We acknowledge that the AQD has proposed a more rigorous leak detection requirement for small well sites in the Basin than what is required for new well sites (an annual instrumented inspection, as well as three other inspections each year). We agree that the very same technologies and practices capable of eliminating or minimizing emissions from new equipment is readily available, economical, and feasible for existing sources.

However, as proposed the rules fall short in some areas in fulfilling DEQ's responsibility to "eliminate pollution" and "enhance the air" in the UGRB NAA.[12] Specifically, due to the use of a four ton per year VOC threshold for many of the control requirements and the failure to apply the requirements to sources located at compressor stations, the rules only address a very small fraction of the emissions in the UGRB NAA. Specifically, based on the 2011 emission inventory for the UGRB NAA and the AQD's Statement of Basis, the proposal applies to only approximately 1% of the existing storage tanks and 15% of the existing glycol dehydrators. Furthermore, only 3% of the existing well sites with fugitive emissions would be required to conduct instrument-based leak inspections on a quarterly basis; the remaining 97% need only check for leaks with modern leak detection technology once a year. While initially subject to control requirements, after one year, nearly all existing pumps could be uncontrolled under the proposal.

Fortunately, these deficiencies are readily addressed with proven, highly cost effective technologies and practices that in many instances save operators money. To ensure the AQD fulfills its mandate to eliminate pollution and enhance the air quality in the Basin, as well as protect the public health, we recommend the following:

- Quarterly instrumented inspections at well sites with at least 2 tons of uncontrolled fugitive VOCs per year
- Extension of the proposal to midstream compressor stations. In particular, require:
    - operators conduct quarterly instrument-based inspections at compressor stations;
    - replace high-bleed pneumatic devices with no or low-bleed devices;
    - replace natural gas fired pneumatic pumps with electric ones, or route emissions to a closed loop system;
    - control emissions from wet seals on centrifugal compressors by 95%;
    - replacement of reciprocating rod-packing every 26,000 hours or three years;
    - control tank and dehydration units by 98%.
- Extend federal control and maintenance requirements for new centrifugal and reciprocating compressors to existing compressors in the production sector
- Strengthen the pneumatic pump control proposal to require the use of electric powered pumps. Only where operators demonstrate doing so is not feasible, based on site-specific

11 See 5 C.C.R. 1001-9, CO Reg. 7, § XVII-XVIII (Feb, 24, 2014); 40 C.F.R. § 60.5360 *et seq.*
12 WY ENV. QUALITY ACT § 35-11-102.

information, should the use of natural gas fired pumps be allowed. In this instance, require operators route emissions to a closed loop system. Flaring should only be permitted as a last resort, if, again, operators demonstrate, based on site-specific analysis, that capturing pump emissions is not feasible;

- Ensure parity between the requirement for new and modified glycol dehydrators in the Jonah-Pinedale Anticline Development and existing dehydrators in the entire UGRB NAA by requiring operators continue to utilize flares to control emissions, regardless of whether emissions drop below four tons of VOCs per year
- Control the entire suite of air pollutants emitted from oil and gas facilities by adopting a total hydrocarbon control standard, rather than only regulating VOCs and HAPs.

II. Proven, Cost Effective Controls are Available to Eliminate or Reduce Natural Gas Emissions from Oil and Gas Facilities in the Basin.

A. Quarterly Inspections are Available and Cost Effective to Reduce Fugitive Emissions from Well Sites and Compressor Stations

Equipment leaks of fugitives from well sites and compressor stations account for approximately one quarter of the VOCs and one quarter of the methane emissions from oil and gas sources in the ozone NAA.[13] Importantly, however, the vast majority of these emissions are not subject to the proposed leak detection and repair ("LDAR") quarterly instrument-based inspection requirement because the scope of the rule does not extend to them (i.e., compressor stations) or they emit less than 4 tons of VOCs per year (97% of well sites).

EG-1-1

Requiring frequent leak inspections with modern, reliable, instruments at all well sites and compressor stations, regardless of emissions potential, is important for two reasons. Emissions reductions increase with leak inspection frequency—hence Colorado, EPA, and ICF report monthly inspections achieve an 80% reduction in fugitive emissions, quarterly inspections achieve a 60% reduction, while annual inspections only reduce emissions by 40%.[14] Second, frequent inspections at a broad range of facilities helps reduce the likelihood that a major leak will go undetected for a long period of time. Top-down inventories and other studies indicate that certain facilities are "super-emitters", meaning they are responsible for very large leaks.[15] Emissions inventories, which are based on standard emission factors and are what operators use to determine facility emissions, do not account for such super-emitters. Thus, certain facilities with estimated VOC emissions under 4 tons per year may be in fact be emitting at a much higher level. Frequent inspections with instruments such as IR cameras that can detect natural gas leaks from multiple pieces of equipment at a facility help ensure that major, as well as minor, leaks are discovered, and repaired, promptly.

1. *LDAR at Well Sites*

[13] 2011 UGRB inventory.

[14] ICF at 3-10.

[15] See e.g., Allen, D. T, *et al.*, Measurements of methane emissions at natural gas production sites in the United States, PNAS (Oct. 2013).

Both the state of Colorado and a recent ICF report demonstrate that quarterly instrument-based inspections are an effective, and economical, way to reduce natural gas emissions from well sites. According to ICF, instrument-based inspections at well sites with 17 tons of uncontrolled fugitive VOC emissions can be accomplished at a cost of $7.60 per Mcf produced (assuming no credit for recovered methane) and $2.52 per Mcf (assuming operators are able to monetize the value of the recovered methane).[16] Per the ICF findings, well site owners are able to monetize the value of recovered methane because the producers own the gas.

Using the ICF cost effectiveness as a framework, EDF estimated the cost effectiveness of requiring quarterly inspections as LDAR at well sites with 2 and 3 tons of fugitives per year. For this analysis we conservatively assumed the same capital, initial and labor costs as ICF. To reflect the fact that an operator of a well site with 2 or 3 tons of fugitives will be able to conduct an inspection more quickly than an operator of a well site with the potential to emit 17 tons of fugitive emissions, we scaled down the per-facility inspection time from 2.2 hours for a facility with 17 tons of fugitives to 2.2 (facility with 3 tons of fugitives) and 2 hours (2 ton facility).

EG-1-2

For the baseline emissions, we ran one case assuming uncontrolled fugitive emissions of 2 tons per year and a second assuming 3 tons per year. Per ICF, Colorado and EPA, we assumed quarterly instrument-based inspections will reduce emissions by 60%. Using these assumptions, we calculated that operators of well sites with 2 tons per year of uncontrolled fugitive emissions can reduce leaks by 60% annually at a cost of $772.62 per ton of VOC reduced. Operators of well sites with 3 tons of fugitives per year can do so at a cost of $559.59 per ton of VOC reduced. We then estimated the potential fugitive methane emissions that could be reduced by quarterly inspections. Potential methane savings from quarterly instrument-based LDAR range from $927 (well site with 2 tons of uncontrolled fugitives per year) to $1,007 (well site with 3 tons of uncontrolled fugitives per year) per ton of VOC reduced. Assuming the value of recovered gas is $4/MCF, we estimate that quarterly instrument-based LDAR inspections can be cost effectively accomplished for $647.15 per ton of VOC reduced at well sites with 2 tons of VOCs per year and $434.12 per ton of VOC reduced at those with 3 tons of uncontrolled fugitives per year. Notably, both the estimate of cost effectiveness assuming gas recovery, and assuming no recovery, are well within the historical determinations of cost effectiveness made by the AQD.[17]

To look at this another way, the AQD's proposal would leave 1,480 tons per year of VOCs in the air that could be easily and cost effectively abated since annual inspections only reduce fugitive emissions by 40% while quarterly inspections can expect 60% reductions.[18] Per the 2011 UGRB inventory, facilities with less than 4 tons of uncontrolled fugitives released 2,467 tons of VOCs to the atmosphere. Reducing these by 40% as the AQD has proposed only results in a reduction of 987 tons per year. More frequent quarterly inspections, on the other hand, will remove 1,480 tons of VOCs from the atmosphere annually – a 67 percent improvement on the AQD's proposal. It is apparent that control of fugitive emissions at emissions rates less than four tons per year via LDAR would be cost-effective and reasonable and could greatly reduce emissions in the Basin.

16 ICF at 3-12.
17 WY DEQ, Division of Air Quality Technical Support Document for Proposed Revisions to the Ch. 6, Sec. 2 Oil and Gas Production Facilities Permitting Guidance (Sept. 2013).
18 ICF at 3-10.

2. *LDAR at Compressor Stations*

EG-1-3

Equipment leaks are one of the most significant sources of pollution at compressor stations. In the Basin, equipment leaks account for approximately 25% of VOC emissions from compressor stations and at least 26% of CH4 emissions.[19] As noted above, actual CH4 emissions are in fact higher since the inventory includes compressor stations in the transmission and storage sector that handle processed gas with very low VOC content. As a result, VOC inventories underrepresent the actual CH4 emissions from downstream compressor stations (as well as other sources).

A robust instrument-based LDAR program can cost effectively reduce fugitive emissions from compressor stations, just as it can from well sites. Both Colorado and Pennsylvania require quarterly instrument-based inspections at compressor stations. Pennsylvania's requirements apply to all non-Title V compressor stations in the production, processing and transmission sectors that quality for its General Permit.[20] Colorado requires monthly, quarterly, and annual instrument-based inspections at all compressor stations in the production (including gathering and boosting) sectors. Inspection frequency is tiered to emissions potential. Sites with 12 tons of uncontrolled VOCs or less require annual inspections. Those with between 12 and 50 tons of uncontrolled VOCs require quarterly inspections while those with over 50 tons of uncontrolled VOCs require monthly inspections. According to the Colorado Air Pollution Control Division annual inspections at compressor stations with between 0 and 12 tons of fugitives costs $165 per ton of VOC reduced, and results in the reduction of 10.1 tons of VOC per year. Quarterly inspections at larger facilities with at least 12 tons of fugitives, and less than 50 tons of VOCs, costs $984 per ton of VOC reduced and will remove 16.4 tons of fugitives from compressor stations in this tier annually.[21] The ICF report similarly found quarterly inspections to be highly cost effective at a $0.91-$5.98 per Mcf for gathering and boosting compressor stations, depending on whether or not operators are able to monetize the value of the recovered methane.[22] Consequently, it is clear LDAR should be required at compressor stations as part of this existing sources rule. Based on the ICF report, we recommend DEQ require quarterly inspections at all compressor stations.

3. *Control and Maintenance Requirements for Seals and Rod-Packing*

In addition to leaks from valves, pumps, connectors and other "components" located at various types of equipment at compressor stations, leaks from reciprocating compressor rod packing and

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19 2011 UGRB Inventory.

20 General Plan Approval and/or General Operating Permit BAQ-GPA-GP-5 (2013), Pa. Dep't of Envtl. Prot., General Permit for Natural Gas Compression and/or Processing Facilities (GP-5), http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-94153/2700-FS-DEP4403.pdf.

21 Colorado Air Pollution Control Division, Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7 (Feb. 7, 2014), Tables 26 and 32. Colorado estimated the overall cost effectiveness of implementing its compressor station LDAR program. To calculate the cost effectiveness of the annual and quarterly inspection programs individually, we relied on the total costs in Table 26 for the 147 smallest compressor stations and 53 mid-sized stations, and the net VOC reductions estimated for these facilities in Table 32.

22 ICF at 3-12.

wet seals on centrifugal compressors emit VOCs, HAPs, and CH4.[23] EPA's New Source Performance Standards address certain of these leaks, specifically leaks from new compressors in the processing and gathering and boosting sectors. However, the federal requirements do not apply to existing compressors, nor do they apply to those located at a well site or further downstream of a gas processing plant, such as in the transmission sector.

EG-1-4

To address existing compressor leaks, Colorado recently adopted rules which extend the federal requirements to existing compressors.[24] Mitigating these types of compressor leaks is highly cost effective. The Colorado Air Pollution Control Division found replacement of rod-packing at reciprocating compressors costs only $43 per ton of VOC reduced. ICF similarly estimated this maintenance practice has a negative cost of -$4.87 per Mcf for those operators who can recover and sell the captured methane, and only $0.21 per MCF for those who are not able to monetize this value. ICF similarly found requiring 95% control of wet seal emissions at centrifugal compressors highly cost effective, at a negative cost of -$3.08 per MCF. Colorado did not analyze the cost effectiveness of this requirement.

We are aware Wyoming does not have emissions information for these types of leaks in its inventory. However, undoubtedly these types of compressors exist in the UGRB NAA, and according to ICF's recent report, they are among the largest sources of methane (and therefore also emit other compounds contained in natural gas) in the industry.[25] In light of the cost savings available to most operators, (and the overall cost effectiveness of the requirements, even for those operators who do not own the gas) we urge the AQD to adopt these demonstrated requirements.

B. <u>Cost Effective Solutions Are Available to Reduce Emissions from Equipment Located at Compressor Stations</u>

EG-1-5

In its April 2014 UGRB Ozone Strategy the AQD committed to the development of "a Phase I control strategy and regulatory option to reduce emissions from existing upstream and midstream oil and gas sources while preserving the current New Source Review permitting processes."[26] It further noted that it will also evaluate a "Phase II emission budget based control strategy and regulatory option to reduce emissions from existing upstream and midstream oil and gas sources."

The current proposal applies only to production (i.e., upstream) sources. It does not include midstream sources, such as compressor stations, in contradiction to the clear statement in the Ozone Strategy that the Phase I regulatory strategy will apply to midstream sources.

Equipment leaks, pneumatic devices and pumps, glycol dehydrators, and tanks were responsible for at least 13,179 tons of VOC emissions and 42,817 tons of CH4 emissions in the Basin in 2011.[27] Actual emissions of methane are likely larger as the inventory includes some

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23 *See* 40 C.F.R. § 60.5360 *et seq.*.
24 5 C.C.R. 1001-9, CO Reg. 7, § XVII-XVIII (Feb, 24, 2014).
25 ICF at Table 3-2.
26 DEQ UGRB Ozone Strategy, 4 (April 2014).
27 2011 UGRB Inventory.

compressor stations located downstream of gas processing plants. Because gas plants remove impurities, such as VOCs, from natural gas, emissions from downstream sources tend to be very low in VOCs, but high in other natural gas compounds such as methane.

The very same cost-effective and reasonable control strategies the AQD has proposed for storage tanks, dehydration units, pneumatic pumps and controllers, and fugitives located in the production sector can be applied to these same sources at compressor stations.[28] Accordingly, we recommend the AQD include compressor stations in the scope of the proposal. In addition, as noted below, we urge the AQD to adopt additional requirements for leaks at centrifugal and reciprocating compressors located in both the midstream and production sectors.

C. Pneumatic Pump Emissions Can Be Eliminated

EG-1-6

We commend DEQ for including a requirement that owners and operators of pneumatic pumps must control emissions by 98% or route the pump discharge streams to a sales line, collection, fuel supply line or other closed loop system. Pumps, along with pneumatic controllers, are the largest source of VOCs and CH4 in the Basin, based on the 2011 inventory. However, in light of the significance of this emissions source, we respectfully urge the AQD to strengthen this requirement.

According to ICF, in addition to capturing or combusting pump emissions, another feasible, highly cost-effective option is to replace natural gas powered pumps with electric ones. For chemical injection pumps this conversion can be accomplished for a cost of $5,000 per pump, at an annual reduction of 180 Mcf per year and at a negative cost effectiveness of -$0.22/Mcf.[29] At well sites where grid electricity is often not available, operators have powered electric chemical injection pumps with solar energy.[30]

Kimray pumps are another form of gas-powered pumps responsible for emissions. Kimray pumps are used to circulate glycol in gas dehydrators. Like chemical injection pumps, kimray pumps can be powered by electricity, thus eliminating natural gas emissions. Kimray pumps, however, require grid electricity. For those well sites in the Basin with access to grid electicity, the conversion of gas-powered Kimray pumps to electricity can be accomplished at a negative cost of -$0.51 per Mcf (assuming gas recovery) or $4.57 per Mcf (if gas is flared).[31]

Given the availability of these highly cost effective, available technologies that eliminate all natural gas pump emissions, we recommend the AQD require use of electric powered pumps, unless the operator demonstrates doing so is not feasible, based on site-specific information. If replacement is not feasible, operators should be required to route emissions to a closed loop system. Flaring should only be permitted as a last resort, if, again, operators demonstrate, based on site-specific analysis, that capturing pump emissions is not feasible. Putting in place strong emissions prevention and/or capture requirements accomplishes the Environmental Quality Act

[28] *See* Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, (March 2014); 5 C.C.R. 1001-9, CO Reg. 7, § XVII-XVIII (Feb, 24, 2014).
[29] ICF at 3-16.
[30] *Id.*
[31] *Id.*

EG-1-7

goal of eliminating air pollution and provides the maximum protections to public health and environment. It also addresses a deficiency in the proposal, namely that if operators are allowed to remove pump controls once emissions have fallen below 4 tons per year, the vast majority of existing pump emissions will be released to the atmosphere.[32] The cumulative impact of allowing nearly all of the pumps to remove controls is the allowance of anywhere between 3,500 to 10,500 tons of VOCs[33] into the atmosphere annually. This should not be permitted.

D. Glycol Dehydrator Control Removal Should not Be Allowed

EG-1-8

In addition to being a significant source of VOCs and CH4, glycol dehydrators are responsible for 67% of the HAP emissions from production sources in the Basin, based on the 2011 inventory. Indeed, due to production characteristics, the existing 2,027 dehydrators in the Basin account for nearly 100% of the HAP emissions from this significant source statewide.[34]

To address emissions from this significant source the AQD has proposed to require XX. Operators may remove combusters, however, after one year if emissions have dropped below, and are expected to remain below, 4 Tpy a year. Based on the 2011 inventory, this could result in control removal from approximately 85% of the dehydrators in the Basin.

We object to the control removal allowance. Operators of new and modified dehydration units in the Jonah-Pinedale Anticline Development ("JPAD") area are allowed no such exception. Existing dehydrators in the Basin should all be treated the same, regardless of whether located in the JPAD or other parts of the UGRB NAA. This is particularly important in light of the significant HAP emissions emitted from dehydrators.

E. Requirements for Pneumatic Controllers and Produced Water Tanks Should be Clarified

EG-1-9

We respectfully request the AQD clarify a few aspects of the proposal. It is our understanding from conversations with Staff that the requirement to replace high-bleed continuous controllers with low-bleed ones applies to both intermittent and continuous bleed devices. It is similarly our understanding that the requirement to control flash emissions from tanks and separation vessels that emit 4 tons of uncontrolled VOCs or more applies to produced water, as well as crude oil and condensate tanks. Notably, replacement of both continuous bleed and intermittent pneumatic controllers is highly cost effective. ICF found that replacing a high-bleed continuous bleed controller with a low bleed yields a net savings of \$-3.08 per MCF while replacing a high-bleed intermittent device yields a reduction cost of \$0.58 per Mcf.[35] The Colorado Air Pollution Control Division similarly recently found that its requirement that operators replace high-bleed continuous bleed controllers with low-bleed ones results in a net annual gain of \$1,084 per

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32 Based on 2011 emissions data and Statement of Basis

33 According to the Statement of Basis, there were 3,506 pumps in the Basin in 2011. Of these, only 6 had emissions over 4 tons of VOCs per year. Assuming that each of these 3,000 pumps has 1 ton of VOC, the total uncontrolled emissions would be 3,000 tons of VOCs. Assuming each facility had 3 tons of uncontrolled VOCs, the total uncontrolled emissions from existing pumps could be as high as 10,500.

34 Based on 2011 emissions in the Basin and statewide.

35 ICF at 3-16.

replaced device, assuming operators are able to sell the recovered gas.[36] To enhance compliance and enforcement of the rule, we urge DEQ to make its intent to control intermittent bleed pneumatic devices, and produced water tanks, explicit.

III. DEQ Should Move Towards Controlling the Full Suite of Pollutants Entrained in Natural Gas Emissions

EG-1-10

As noted above, natural gas consists primarily of methane-a potent greenhouse gas-as well as a suite of VOCs, including known human carcinogens such as benzene and formaldehyde, and in some instances, hydrogen sulfide. Notably, many of the control technologies and practices applicable to reducing one of these compounds is effective at reducing the others. Recognizing this, the state of Colorado recently adopted rules aimed at reducing hydrocarbon emissions, including methane and VOCs, from a similar suite of oil and gas facilities/sources subject to the AQD's proposal.[37] Specifically, Colorado requires control of hydrocarbon emissions from new and existing storage tanks, dehydrators, pneumatic controllers, equipment leaks at well sites and compressor stations, and separators.. We urge Wyoming to adopt the approach taken by its neighbor to the south and require the control of all hydrocarbon emissions from oil and gas facilities, not just VOCs and HAPs.

IV. Conclusion

We greatly appreciate the initial steps DEQ has taken to address emissions from existing oil and gas sources in the Basin. For the reasons noted above we urge the DEQ to strengthen the proposal as detailed in our comments in order to provide the maximum level of protections to public health and the environment.

Respectfully submitted,

Jon Goldstein
Elizabeth Paranhos
Environmental Defense Fund

And on behalf of:

Bruce Pendery
Wyoming Outdoor Council

Elaine Crumpley
CURED

[36] APCD Cost-Benefit Analysis, Table 39.
[37] 5 C.C.R. 1001-9, CO Reg. 7, § XVII-XVIII (Feb, 24, 2014).

Air Quality Advisory Board Meeting—Rock Spring—July 14, 2014
Statement of Bruce Pendery

Thank you for the opportunity to present comments to the Air Quality Division and the Air Quality Advisory Board regarding the proposed regulation of air pollution emissions from existing oil and gas sources in the Upper Green River Basin ozone nonattainment area.

My name is Bruce Pendery and I am the chief legal counsel for the Wyoming Outdoor Council.

Generally speaking we are supportive of this proposal and encourage its adoption. We believe it will help to improve air quality in the Upper Green River Basin, helping to bring the area back into compliance with the National Ambient Air Quality Standard for ozone and better protect the health of people who live in the area. These would be important and worthy accomplishments.

But as we indicated in the written comments we have submitted to the Air Quality Division in conjunction with our partners at the Environmental Defense Fund and which I hope the Advisory Board has had some opportunity to review, we do believe there are several areas in which the proposed rules could be improved. Those areas of needed improvement include providing for quarterly inspections of leaks or fugitive emissions at oil and gas facilities even when those facilities emit less than 4 tpy of volatile organic compounds, not just annual inspections, as the proposed rule currently provides, the need to regulate emissions from compressor stations, and the need to not allow emissions control measures to be removed at dehydration units and pneumatic pumps after one year if emissions of VOC are less than 4 tpy. As our comments indicate, we believe there are very cost effective means to regulate these emissions. I will not spend more time on these issues in these comments because you can look at our written statement, and in addition my partner from EDF, John Goldstein will tell you more about these concerns.

There are, however, several other issues of concern or points I would like to highlight for you.

EG-2-1

First, under the proposed rule, for both flashing emissions and emissions from dehydration units controls for emissions would be required at both PAD facilities and single well facilities only if emissions of hazardous air pollutants or VOC exceed 4 tpy. This provision is different than the provision for controlling flashing emissions and dehydration unit emissions at new and modified oil and gas sources that is specified in the Air Divisions Upper Green River Basin Presumptive Best Available Control Technology or P-BACT guidance where emissions controls for these emissions at <u>PADs</u> are required no matter what the emission level is. The P-BACT guidance does not require a 4 tpy threshold of HAP and VOC emissions prior to requiring control of those emissions at PAD facilities, any emissions at PADs trigger the need for controls. We are not sure why this existing source rule should require a lesser level of pollution control at these <u>PAD</u> facilities for flashing and dehydration unit emissions, and think this issue should be reconsidered.

EG-2-2

Second, under the proposed rule, emissions requirements would be established for flashing, dehydration units, pneumatic pumps, pneumatic controllers, and for fugitive emissions. There would be no provisions for controlling emissions from produced water tanks or from blowdown and venting operations. This is in contrast to the P-BACT guidance which in addition to the mentioned areas of control also has specific requirements for controlling emissions from produced water tanks and from blowdowns and venting. It is not clear to us why the existing source rule should not also require emissions reductions from produced water tanks and blowdown and venting, and we urge modification of the rule to incorporate these additional emissions controls. Now it could be argued the current provision for controlling flashing emissions would also extend to produced water tanks since it mentions and I quote "produced oil, condensate and water tanks," however, the P-BACT guidance also makes mention of flashing provisions applying to produced water, but it nevertheless provides for controlling produced water tank emissions in an entirely separate section. We think the same provisions should be strongly considered for the existing sources rule.

EG-2-3 Third, under the proposed rule two defined terms are what are called a "composite extended hydrocarbon analysis" and an "extended hydrocarbon analysis." These would be gas chromatograph analyses of oil and condensates and natural gas at oil and gas production facilities that would identify hydrocarbons in the C1 – C10 range including the hazardous air pollutants benzene, toluene, ethyl-benzene, and xylenes—the BTEX chemicals—and n-hexane and 2-2-4-trimethylpentane. The proposed rule would then put in place requirements to do the composite extended hydrocarbon analysis for determining emissions from flashing and dehydration units. We are supportive of this provision because we believe the analysis of air pollutants from oil and gas facilities in the Upper Green River Basin should be extended to a wider range of hydrocarbons than just VOC. In our view it would be appropriate to also control methane emissions from oil and gas facilities in the Upper Green because methane is a very potent greenhouse gas, and extending the analysis to hydrocarbons will help ensure there is monitoring of this potential pollutant, even if there is not direct regulation of it. This might help us to determine if we are also achieving reductions of methane emissions in the Upper Green as a "co-benefit" of the existing source regulations, to use the term that EPA has coined for this indirect form of emissions controls. So we encourage the Division to maintain these requirements for composite hydrocarbon analyses.

EG-2-4 Fourth, pursuant to the table presented in the Air Divisions Statement of Basis memorandum for this rulemaking it is apparent that the vast majority of pollution sources in the Upper Green—tanks, dehydration units, pumps, controllers, and fugitives—have emissions below the 4 tpy threshold. This raises a concern about whether the 4 tpy threshold is the appropriate threshold and we urge consideration of whether a threshold at lower emissions rates should be adopted.

EG-2-5 Fifth, as has been made clear to us, this current effort to develop a technology based approach to controlling emissions in the Upper Green is just Phase I of a two part process. In Phase II the Division intends to develop an emissions budget approach to controlling emissions in the Upper Green. We are very supportive of this Phase II effort, and urge the Division to pursue it as promptly as possible and to not permit any delays in developing these additional regulations.

EG-2-6 Finally, as far as we have seen, nowhere is there a statement of what the total level of emissions reductions will be as a result of adopting this existing source rule. We think this is vital information that would be very useful to the public. How much pollution reduction are we going to get and what are the anticipated or hoped for benefits to air quality from this action? How many tons per year less VOC and NOX are we going to see? We believe there should be such a statement and we urge the Air Quality Division to publish this information.

Thank you for considering these comments.

ANADARKO PETROLEUM CORPORATION 1099 18TH STREET, SUITE 1800 • DENVER, CO 80202-1918
P.O. BOX 173779 • DENVER, CO 80217-3779

Anadarko Petroleum Corporation

July 10, 2014

Steven A. Dietrich
Air Quality Administrator
Herschler Building 2-E
122 W. 25th Street
Cheyenne, WY 82002

Re: Comments on Proposed Rule Change to Wyoming Air Quality Standards and Regulations, Chapter 8, Nonattainment Area Regulations

Dear Mr. Dietrich:

Anadarko Petroleum Corporation (APC) appreciates the opportunity to comment on the Wyoming Department of Environmental Quality Air Quality Division's (Division) proposed revisions to the to Wyoming Air Quality Standards and Regulations, Chapter 8, Nonattainment Area Regulations.

APC supports the Division's proposal to address the non-attainment area through regulation of existing sources. To ensure an effective rule with sufficient time to comply, APC has included suggested changes to the rule, in the body of this letter. APC requests that the Division hold additional stakeholder engagement opportunities in order to address the comments that require further dialogue to ensure an effective revision.

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Comment 1: APC has reviewed the statement of basis and requests that the Division provides the anticipated emission reductions from the rulemaking, an estimate of the number of affected sources, and quantification/estimation of the cost to implement. The statement of basis indicates this is the first phase of a two phase approach. APC feels that knowledge of the second phase is important in order to properly comment on the first phase.

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Comment 2: APC suggests removing the term "Responsible Official" in the definition section, and from the reporting requirements in Section 6 (h)(iii)(G). A Chapter 6, Section 3 definition is inappropriate and burdensome for minor sources. Language similar to that found Chapter 6, Section 2(b)(i) would be more appropriate for minor source requirements. The owner of the facility or the operator of the facility, authorized to act for the owner, is responsible and shall certify the report. Section 6 (h)(iii)(H) references the owner and operator for submittal and should remain consistent in Section 6 (h)(iii)(G).

P-1-3 **Comment 3:** APC believes that a phase-in period is necessary for all sources (tanks, dehydration units, pneumatic pumps, and pneumatic controllers) to successfully implement the control and retrofit requirements. Depending on the date the rule is finalized, the current date of January 1, 2016 may not allow for enough time to plan for and complete the required retrofits. Determination of an appropriate phase-in period could be addressed in additional stakeholder meetings.

P-1-4 **Comment 4:** APC requests that the Division clarify that the 98% control requirements for tanks and dehydration units are the manufacturer designed destruction efficiency for VOCs.

P-1-5 **Comment 5:** Emergency, open-top, and/or blowdown tanks should be excluded from this rulemaking. Venting and blowdown permits, required under the Division's oil and gas guidance, apply to all new and existing wells. Including requirements for blowdown tanks in the rule will be duplicative and/or contradictory. Based on the record-keeping the Division has received from these permits, the Division has stated that emissions from blowdown and venting are not a significant source of emissions and thus, additional recordkeeping adds little benefit.

Emergency tanks are regulated under Chapter 1, section 5 of the WAQSR and additional requirements in the rule create confusion.

P-1-6 **Comment 6:** APC requests that for existing dehydration units where flash tanks and condensers, or just condensers, were installed in lieu of a combustion device per the requirements of prior versions of the oil and gas guidance, the applicability of these rules should allow emission estimates to take into account the use of this equipment.

P-1-7 **Comment 7:** APC suggests removing the language in Section 6 (e)(ii) that allows for control removal from pumps. There is no threshold for control of the pump so a threshold for control removal is not warranted.

P-1-8 **Comment 8:** APC requests that the Division clarify that the requirement to determine component counts in Section 6 (g)(ii)(A)(I) allow for a representative count from a single facility for all similarly designed facilities.

P-1-9 **Comment 9:** APC suggests the language change below for monitoring the combustion device in Section 6 (h)(i)(A). The current language is not clear on how the combustion device can be monitored to ensure the 98% control requirements.

> (A) Combustion Device Monitoring Conditions. If a combustion device is used to control emissions, the combustion device shall be monitored using a continuous recording device or any other equivalent device ~~to ensure the 98% control requirements as specified by these regulations are met.~~ For a combustion device this may be a thermocouple and continuous recording

device or any other equivalent device to detect and record the presence of the pilot flame, or a combustion chamber temperature recorder/monitor.

P-1-10 **Comment 10:** To ensure an effective leak detection and repair program, APC suggests including requirements for timing of repair for the leak detection required in Section 6 (h)(i) (E)(I) and that the LDAR protocol in Section 6 (g)(i) be approved by the Division.

P-1-11 **Comment 11:** APC requests that the Division remove the requirement for recording a reason for the absence of a pilot flame in Section 6 (h)(ii)(I)(1.). Most pilots are monitored by telemetry system that will automatically record downtime and the operator would have to manually input the reason for downtime. This requirement adds a significant amount of additional paper work.

P-1-12 **Comment 12:** APC requests the Division remove the requirement in Section 6 (h)(ii)(A)(III) to record hourly temperature from the reboiler still vent. It is not clear what benefit this data will provide and the requirement adds a significant amount of recordkeeping.

P-1-13 **Comment 13:** APC requests that the Division extend reporting requirements in Section 6 (h)(iii)(A) to identify affected sources. Depending on the date the rule is finalized, the current date of April 1, 2015 may not allow for enough time to gather information and calculate emissions. Submittal of the report by June 30, 2015 will allow operators to utilize the WDEQ emission inventories to calculate emissions and identify affected sources.

P-1-14 **Comment 14:** APC requests that the Division remove the requirement in Section 6 (h)(iii)(B) and Section 6 (h)(iii)(C) to submit quarterly reports identifying installation of control device and equipment and pneumatic device installation. APC believes that one annual report is sufficient to identify installation of control devices and that the implementation of the leak detection program have met the implementation deadline. If the Division allows for a phase-in period for installing control device and pneumatic devices, annual reports will be submitted to verify progress towards the phase-in requirements.

P-1-15 **Comment 15:** APC requests that the Division extend the deadline in Section 6 (h)(iii)(D) to submit the final notification of installation to March 31, 2016, this will allow for sufficient time to gather required information.

P-1-16 **Comment 16:** It is unclear how this rule will affect the "Interim Permitting Policy for Sources in Sublette County", specifically concerning generation of new credits, which is necessary for new operators. APC requests that the Division explain how the interim policy and the proposed rule will coexist, or clarify if this rule will eliminate the need for the interim policy.

APC appreciates the Division's considerations of the above comments in order to create an effective rule.

Sincerely,

Chad Schlichtemeier

Chad Schlichtemeier
HSE Rockies Air Manager

PETROLEUM ASSOCIATION OF WYOMING

951 Werner Court, Suite 100
Casper, Wyoming 82601
(307) 234-5333

fax (307) 266-2189
e-mail: paw@pawyo.org
www.pawyo.org

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RECEIVED
AIR QUALITY DIVISION

Steven A. Dietrich
Air Quality Administrator
Herschler Building 2-E
122 W. 25th Street
Cheyenne, WY 82002

Re: Comments on Proposed Rule Change to Wyoming Air Quality Standards and Regulations, Chapter 8, Nonattainment Area Regulations

Dear Mr. Dietrich:

The Petroleum Association of Wyoming (PAW) would like to take this opportunity to provide comments to the Wyoming Department of Environmental Quality (WDEQ) Air Quality Division (AQD) concerning the proposed revisions to the proposed rule change to Wyoming Air Quality Standards and Regulations, Chapter 8, Nonattainment Area Regulations.

PAW is Wyoming's largest oil and gas trade association. PAW members produce over 90% of the natural gas and 80% of the crude oil in the state and have a vested interest in the policies, rules and regulations administered by the WDEQ.

PAW supports the Division's proposal to address the non-attainment area through regulation of existing sources. While we appreciate the intent of the rule, we believe this rule lacks clarity and has many ambiguities, inconsistent definitions, and onerous administrative requirements. Numerous revisions to this proposal are required to make this a workable final rule. The following paragraphs detail the areas of the rule that are of particular concern. PAW recommends additional stakeholder meetings in order to address the larger concerns.

Importantly, the January 1, 2016 compliance date is not feasible considering the breadth of affected facilities impacted by this rule. Nearly 300 glycol dehydrators alone may require emissions control. Regulatory precedent already exists for a 3 year phase-in period when regulating existing sources due to the time required for planning, budgeting, contracting, purchasing, scheduling, and construction. Additionally, many sites may require construction to enlarge existing pads to accommodate controls. Midstream operators of glycol dehydrators may be dependent on production operators to complete this construction work before installing emission controls.

PAW reviewed the statement of basis and does not believe it provides the basis for the control thresholds required in the rule. PAW is also interested in seeing the emission reductions that will be achieved, an estimate of the number of affected sources, and quantification/estimation of the cost to implement. In addition, the Statement of Basis indicates this is the first phase of a phased approach, but information about Phase II is limited to that presented in the Ozone Strategy, which says that the Division will "Evaluate a Phase II emission budget based control strategy and regulatory option to reduce emissions from existing upstream and midstream oil and gas sources." This lack of detail about the second phase of the approach makes it difficult to evaluate how the two-phase approach will work and the overall effectiveness of phase I.

PAW suggest a change to the definition of existing sources, in order to exclude sources that are subject to the more recent Presumptive BACT (p-BACT) Guidance revisions.

PAW recommends removing requirements for emergency and blowdown tanks. Venting and blowdown permits, required under AQD's p-BACT, apply to all new and existing wells. Including requirements for blowdown tanks in the rule will be duplicative and/or contradictory. In addition, emergency tanks are regulated under Chapter 1, section 5 of the WAQSR and additional requirements in the rule create confusion.

Our detailed comments are attached for your review.

Thank you,

John Robitaille
Vice President

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Proposed Rule	Comments
(a) Applicability. (i) These regulations apply to all single well and multiple well pad oil and gas production facilities or sources and all associated production equipment located in the Upper Green River Basin (UGRB) ozone nonattainment area that were existing as of January 1, 2014. The Upper Green River Basin ozone nonattainment area is that area which was adopted by reference from 40 CFR part 81.351, revised and published as of July 1, 2013, not including any later amendments. Copies of the Code of Federal Regulations (CFR) are available for public inspection and can be obtained at cost from the Department of Environmental Quality, Air Quality Division, Cheyenne Office. Contact information for the Cheyenne Office can be obtained at: http://deq.state.wy.us. Copies of the CFR can also be obtained at cost from Government Institutes, 15200 NBN Way, Building B, Blue Ridge Summit, PA 17214, or online at: http://www.gpo.gov/fdsys/browse/collectionCfr.action?collectionCode=CFR.	PAW members operating in the area estimate that approximately 750-800 locations will need to be evaluated for fugitive and tank emissions. Many of these locations will also need to control pneumatic pumps and be retrofitted with low bleed controllers. There is an estimated 300 dehy units that will likely need controls. The pneumatic pumps and controllers associated with these dehys will also have to be controlled or retrofitted. It is unclear what the phrase "or sources and all associated production equipment located in the Upper Green River Basin ozone nonattainment area" is referring to. Is it limited to production equipment located on a single or multiple well pad or is this rule meant to extend to sources beyond single/multiple wells pads? P-2-1
(ii) A facility or source shall comply with all applicable requirements of these regulations unless a Wyoming Air Quality Standards and Regulations (WAQSR) Chapter 6, Section 2 permit has been issued, which much be as stringent or more stringent than the requirements of these regulations; and	This is very ambiguous and for each site suggests a line by line comparison between this rule and each permit to determine stringency then pick applicable requirements. The rule should specifically say that if you have a minor source permit issued using the latest p-BACT guidance effective 11/1/2013 or Chapter 6, section 2 permit issued since latest revision (11/22/2013), then you are exempt from this rule, otherwise you must comply. P-2-2 Replace word "much" with "must" P-2-3 There should also be a provision that encourages or allows operators to install controls on existing facilities ahead of the compliance date, and seek reauthorization under the 2013 permitting guidance as an alternative means to be exempt from this rule but still comply with its objectives. This would be voluntary and work similarly to a synthetic minor permit to opt out of major source requirements. P-2-4

Proposed Rule	Comments
(iii) Notwithstanding the requirements of Chapter 6, Section 2(a)(i) and (iii) of the WAQSR, a preconstruction permit under Chapter 6, Section 2 is not required for any control device (flare/enclosed combustion unit) or equipment identified in these regulations unless a facility or source is required to obtain a permit under Chapter 6, Section 4 or Section 13. Upon Division approval, an alternative emission control device and/or equipment may be used in lieu of, or in combination with, a combustion device to achieve the 98% control efficiency required by these regulations.	Replace 98% control requirement with device with manufacturer-designed destruction efficiency of 98% for VOCs
(b) Definitions. **"Composite extended hydrocarbon analysis"** are averaged extended hydrocarbon compositions based on samples from at least five wells producing from the same formation and under similar conditions (± 25° psig) as the well being permitted.	
"Dehydration unit" means a system that uses glycol to absorb water from produced gas before it is introduced into gas sales or collection lines.	

Proposed Rule	Comments
"Extended hydrocarbon analysis" means a gas chromatograph analysis performed on pressurized hydrocarbon liquid (oil/condensate) and gas samples taken from the separation equipment under normal operating conditions (temperature and pressure) at oil and gas production facilities. All samples shall include both speciated hydrocarbons from methane (C1) through decane (C10), including the following Hazardous Air Pollutants (HAPs); benzene, toluene, ethyl-benzene, xylenes (BTEX), n-hexane, and 2-2-4-trimethylpentane.	Inappropriate to include where sample must be taken in this definition. Definition should only speak to the type of analysis, not how a sample should be taken. Where sample should be taken should be stipulated elsewhere in the emissions determination sections (c)(ii)(C) and (d)(ii)(C). Definition should just include the species to be sampled for. Examples: Speciated working and breathing losses from a tank require an extended analysis from sample taken from the tank itself not a separator. Speciated fugitive emissions may require a gas sample after dehydration.
"Facility components" consist of flanges, connectors (other than flanges), open-ended lines, pumps, valves and "other" components listed in Table 2-4 from EPA-453/R-95-017 at the site grouped by stream (gas, light oil, heavy oil, water/oil). Table 2-4 from EPA-453/R-95-017 can be found online at: http://deq.state.wy.us/aqd/oilgas.asp or http://www.epa.gov/ttnchie1/efdocs/equiplks.pdf.	
"Flashing emissions" means losses that occur when produced liquids (crude oil or condensate) are exposed to temperature increases or pressure drops as they are transferred from pressurized vessels to lower pressure separation vessels or to atmospheric storage tanks. **"Fugitive emissions (fugitives)"** means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.	
"Optical gas imaging instrument" means an instrument that makes visible, emissions that may otherwise be invisible to the naked eye.	
"PAD facility" means a location where more than one well and/or associated production equipment are located, where some or all production equipment is shared by more than one well or where well streams from more than one well are routed through individual production trains at the same location.	For clarity and consistency, definition should use identical wording as that in the 9/2013 revision to the permitting guidance document.

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"Responsible Official" means a responsible official as defined in 40 CFR §60.5430.	This term is used in the reporting section (h)(iii)(G). Chapter 6, Section 3 definition is inappropriate and burdensome for minor sources, so should refer to NSPS, Subpart OOOO definition for consistency which is under revision in the current proposal released on 7/1/2014 to be more appropriate for minor sources
"Separation vessels" means all gun barrels, production and test separators, production and test treaters, water knockouts, gas boots, flash separators and drip pots.	
"Single well facility" means a facility where production equipment is associated with only one well.	For clarity and consistency, definition should use identical wording as that in the 9/2013 revision to the permitting guidance document.
"Storage tanks" means any tanks that contain oil, condensate, produced water or some mixture thereof.	
(c) Flashing Emissions at an Existing Facility or Source as of January 1, 2014. (i) Vapor streams containing VOC or HAP components from all existing storage tanks and all existing separation vessels are subject to these regulations. (A) PAD Facilities and Single Well Facilities. For total uncontrolled VOC emissions from flashing emissions that are greater than or equal to 4 tpy, VOC and HAP flashing emissions from all produced oil, condensate and water tanks shall be controlled to at least 98% by January 1, 2016. (B) Storage tanks that are on site for use during emergency or upset conditions are not subject to the 98% control requirements. (C) Emergency, open-top and/or blowdown tanks shall not be used as active storage tanks but may be used for temporary storage. (I) Emergency tanks shall be utilized for malfunctions only as allowed in Chapter 1, Section 5 of the WAQSR. (II) If emergency, open-top and/or blowdown tanks	A 1/1/2016 compliance date is too soon for an existing source rule. Operators, especially those that will have numerous affected facilities cannot respond and comply that quickly. A realistic time period needs to consider the planning, budgeting, purchasing, and construction needed to comply. Existing source rules typically have a 3-yr phase in period from the promulgation date of the rule, and that is needed here. Many examples of longer phase-in periods are in current rules including EPA NESHAP rules such as 40 CFR 63, Subparts HH and ZZZZ. As well, EPA NSPS, Subpart OOOO has 3 year phase in periods for a number of sources including storage vessels (Group 1 tanks) and reduced emission completions. Examples of other state nonattainment existing source rules with 3-yr. phase in periods include TCEQ Title 30 chapters 115 and 117. In paragraph (c)(i)(C)(II) PAW believes the requirement for blowdown tanks should be removed. This blanket requirement does not consider the quantity of liquids produced, nor associated emissions. It would be cost prohibitive and potentially increase emissions due to a large increase in truck runs.

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are utilized, they must be emptied within seven (7) calendar days. (D) Control Removal. The removal of flashing emissions control devices will be allowed after one year from the date of installation if uncontrolled VOC flashing emissions have declined to less than, and will remain below 4 tpy.	Replace 98% control requirement with device with manufacturer-designed destruction efficiency of 98% for VOCs
(ii) Applicability Determination for Flashing Emissions. (A) Determine the average daily condensate or oil production for calendar year 2013 in barrels per day (bpd). (B) Use a Division-approved flash emissions model or direct measurement of tank emissions to determine uncontrolled VOC and HAP emissions. (C) Model input shall consist of: (I) A site-specific or composite extended hydrocarbon analyses of liquids <u>using a pressurized sample(s) from a separator;</u> (II) Average daily oil/condensate production rate as determined in Subsection (c)(ii)(A) of these regulations; (III) The average, actual equipment operational parameters, including separator temperature and pressure and API gravity and Reid vapor pressure (RVP) of sales oil; and (IV) Samples shall be no older than three (3) years from date of applicability determination or control removal.	Determination in (ii)(A) is unreasonable. Emissions could be below threshold by compliance date. Should use a timeframe more representative of current operating conditions near the time controls are required to be installed to determine applicability. By the compliance date, emissions could be below 4 tpy. Using 2013 as emissions threshold baseline assumes steady state production without accounting for production decline. Paragraph (C)(I) a site specific sample should not be required. Representative analysis should be allowed. The TCEQ has guidance for determining what is representative if necessary. Paragraph (C)(III) RVP of sales oil is not typically available. Is it the intent of the Division to be a parameter displayed in the model results (based on the pressurized sample used and facility operating conditions modeled)? This needs to be clarified to be an output of the model, not an input.

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(d) Dehydration Units at an Existing Facility or Source as of January 1, 2014. (i) Vapor streams containing VOC or HAP components released from all existing dehydration units are subject to these regulations. (A) PAD Facilities and Single Well Facilities. For total uncontrolled VOC emissions from all dehydration units that are greater than or equal to 4 tpy, VOC and HAP emissions from all dehydration units shall be controlled to at least 98% and equipped with reboiler still vent condensers by January 1, 2016. (B) Control Removal. Combustion units used to achieve the 98% control may be removed after one year from the date of installation if total uncontrolled VOC emissions from all dehydration units are less than, and will remain below 4 tpy, and all dehydration units are equipped with still vent condensers.	A 1/1/2016 compliance date is too soon for an existing source rule. Operators, especially those that will have numerous affected facilities cannot respond and comply that quickly. A realistic time period needs to consider the planning, budgeting, purchasing, and construction needed to comply. Existing source rules typically have a 3-yr phase in period from the promulgation date of the rule, and that is needed here. Many examples of longer phase-in periods of 3 years are in current rules including EPA NESHAP rules such as 40 CFR 63, Subparts HH and ZZZZ. As well, EPA NSPS, Subpart OOOO (though for new sources) has 3 year phase in periods for a number of sources including storage vessels (Group 1 tanks) and reduced emission completions because of the buildup of sources between the proposal of the rule and promulgation. Examples of other state nonattainment existing source rules with 3-yr. phase in periods include TCEQ Title 30 chapters 115 and 117 for tanks and combustion sources respectively. Replace 98% control requirement with device with manufacturer-designed control efficiency of 98% for VOCs
(ii) Applicability Determination for Dehydration Units. (A) Determine the average daily gas production rate for calendar year 2013 in million cubic feet per day (MMCFD). (B) Use GRI-GLYCalc V4.0 or other methods approved by the Division with the annualized average daily production rate to determine annualized uncontrolled VOC and HAP emissions from the dehydration unit process vents. Process vents include reboiler still vents, glycol flash separators and still vent condensers. (C) Model input shall consist of: (I) A site-specific or composite extended hydrocarbon analysis of wet gas; <u>using a pressurized sample(s) from a separator;</u> (II) Average daily gas production rate as determined in Subsection (d)(ii)(A) of these regulations;	For existing dehydration units where flash tanks and condensers, or just condensers were installed in lieu of a combustion device per the requirements of prior versions of the oil and gas guidance, the applicability of these rules should allow emission estimates to take into account the use of this already installed, functioning, equipment, where operating parameters for this equipment are available Determination in (ii)(A) is unreasonable. Emissions could be below threshold by compliance date. Should use a timeframe more representative of current operating conditions near the time controls are required to be installed to determine applicability. By the compliance date, emissions could be below 4 tpy. Using 2013 as emissions threshold baseline assumes steady state production without accounting for production decline.

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Proposed Rule	Comments
(ii) Control Removal. At sites where pneumatic pump emissions are controlled by a combustion unit used for the control of flash or dehydration unit emissions, removal of the combustion unit will be allowed after one year from the date of installation if all the VOC emissions routed to the combustion unit are less than, and will remain below 4 tpy.	The rule implies that all pneumatic pumps emit 4 tpy of VOCs before control is required, if that is the intent please state so explicitly. If there is no threshold for controls PAW requests that this language be removed as it is not warranted.
(f) Existing Pneumatic Controllers as of January 1, 2014. Natural gas-operated pneumatic controllers shall be low (less than 6 standard cubic feet per hour (scfh)) or no-bleed controllers or the controller discharge streams shall be routed into a sales line, collection, fuel supply line or other closed loop system by January 1, 2016.	As mentioned for both dehys and tanks, a 3-yr phase-in period is needed for these existing sources. Compliance date should be 3 yrs from the rule promulgation date. To be consistent with NSPS, Subpart OOOO use of the terms continuous bleed or intermittent vent is recommended. "No-bleed" is a marketing term, not a technical term.
(g) Fugitives. (i) For facilities in existence prior to January 1, 2014, with fugitive emissions greater than or equal to 4 tpy of VOCs, operators shall implement a Leak Detection and Repair (LDAR) Protocol. (A) The LDAR Protocol monitoring schedule shall be no less frequent than quarterly; (B) Shall consist of 40 CFR part 60, Appendix A, Method 21, optical gas imaging instrument, other instrument-based technologies, audio-visual-olfactory (AVO) inspections, or some combination thereof; (C) A LDAR Protocol consisting of only AVO inspections will not satisfy the requirements of this section.	No compliance date for implementation is specified. As with other recommendations above, a 3 yr phase-in should be specified. For clarity and demonstration of permitting guidance equivalence, this paragraph should refer to the advance notification required in (h)(iii)(F). Quarterly inspection frequency is excessive. Even if AVO inspection is allowed, the recordkeeping associated with an LDAR program is overly burdensome to maintain for hundreds of facilities. The LDAR program is not the sole mechanism operators employ to identify and repair leaks. The LDAR program verifies the effectiveness of the operator's existing procedures and helps the operator identify areas for improvement. In addition, analysis of LDAR inspection records reveals that increasing the inspection frequency does not reduce the number of leaks found. Leak rates at initial inspections were similar to subsequent inspections. This reporting frequency should be lowered from quarterly to annual.

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(ii) Applicability Determination for Fugitive Emissions. (A) Fugitive emissions shall be estimated using Table 2-4 from EPA-453/R-95-017, Protocol for Equipment Leak Emission Estimates, and the total facility component count. (I) Facility component counts shall be determined by actual field count. (II) Emission factors in the Protocol for Equipment Leak Emission Estimates are not intended to be used to represent emissions from components that are improperly designed or equipment not maintained properly. (B) Site-specific speciated hydrocarbon emission rates can be estimated by multiplying the total hydrocarbon emission rate estimated in Subsection (ii)(A) above by measured VOC and HAP weight fractions.	Getting actual field counts of fugitive components for hundreds if not thousands of locations will be a time consuming and costly effort, especially for locations where fugitive emissions are not expected to be anywhere near the 4 TPY threshold. Allowance should be made for the use of representative counts of fugitive components from facilities with similar installations. — P-2-26 Additionally, operators who are participating in the Emissions Inventory Study taking place during the summer of 2014, or have actual emission rate data regarding fugitive emission at their locations should be allowed to use that data towards the fugitive emissions applicability in lieu of the requirements of C8,S6(g)(ii)(A). — P-2-27
(h) Monitoring, Recordkeeping and Reporting. (i) Monitoring. The owner or operator of each facility or source shall comply with all applicable monitoring requirements as specified by this subsection. (A) Combustion Device Monitoring Conditions. If a combustion device is used to control emissions, the combustion device shall be monitored using a continuous recording device or any other equivalent device ~~to ensure the 98% control requirements as specified by these regulations are met~~. For a combustion device this may be a thermocouple and continuous recording device or any other equivalent device to detect and record the presence of the pilot flame, or a combustion chamber temperature recorder/monitor. (I) The combustion device shall be designed, constructed, operated and maintained to be smokeless, satisfying the requirements of Chapter 3, Section 6(b)(i) of the WAQSR. (II) Visible emissions shall not exceed a total of five (5) minutes during any two (2) consecutive hours as determined by 40 CFR part 60, Appendix A, Method 22. (B) Reboiler still vent condensers shall be designed to	Monitoring requirements should reflect those specified in the permitting guidance of 9/2013. As written, no monitoring method is specified which leads to ambiguity and confusion. Could it mean a Continuous Emission Monitoring System? Assuming this is meant to reflect equivalent monitoring in the 2013 permitting guidance, that language is inserted in paragraph (i)(A). — P-2-28 This change is required as it is not clear how the combustion can be monitored to ensure the 98% control requirements as the control device does not monitor control, but does monitor the pilot flame. P-2-29 Paragraph (E)(I) effectively stipulates an LDAR program equivalent to paragraph (g) by requiring at least an annual instrument survey. Even if subject to paragraph (g), an operator could use AVO for three quarters, and an instrument one quarter. For sites with fugitive emissions less than 4tpy, AVO should be satisfactory each quarter to differentiate this requirement from that in (g). — P-2-30

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achieve maximum condensation of the condensable components in the still vent exhaust stream by providing the maximum temperature differential between the reboiler exhaust vapors and the accumulated, condensed liquids, with the temperature of the accumulated liquids being lower. (C) All emission control devices and equipment used to reduce VOC and HAP emissions at any facility or source shall be operated and maintained pursuant to manufacturer specifications or equivalent, and consistent with good engineering and maintenance practices. (D) All emission control devices and equipment shall be adequately designed and sized to achieve the control efficiency required by these regulations and to accommodate fluctuations in emissions. (E) Owners or operators shall conduct a quarterly site evaluation of equipment, systems and devices that include, but are not limited to, combustion units, reboiler overheads condensers, storage tanks, drip tanks, vent lines, connectors, fittings, valves, relief valves, hatches, and any other appurtenance employed to, or involved with, eliminating, reducing, containing or collecting vapors and routing them to an emission control system or device. (I) At least one of the quarterly evaluations per calendar year shall consist of 40 CFR part 60, Appendix A, Method 21, optical gas imaging instrument, or other instrument-based technologies. (II) Owners or operators required to implement an LDAR Protocol have satisfied the requirements of paragraph (E) above.	In Paragraph (E)(I) PAW requests inclusion of requirements for timing of repair of quarterly evaluation to ensure effective LDAR program In paragraph (i)(E) The wording of this requirement is unclear. Does this mean that all facilities regardless of the use of a control device must conduct Quarterly site evaluations of their equipment? It is assumed (or requested) that this requirement is just for equipment, "involved with, eliminating, reducing, containing or collecting vapors and routing them to an emission controls system or device."
(ii) Recordkeeping. The owner or operator of each facility or source shall comply with all applicable reporting and recordkeeping requirements as specified by this subsection. Records shall be maintained for a period of five (5) years and made available to the Division upon request. (A) Owner/operator shall maintain the following records for each combustion device:	What if there is no pilot but spark ignition instead as properly allowed in Chapter 3, section 6? This recordkeeping detail isn't specified in permitting guidance which makes this more onerous rather than equivalent to permitting guidance.

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Proposed Rule	Comments
(I) Records of period during active well site operation when the pilot flame is not present, including: (1.) A description of the reason(s) for the absence of the pilot flame; (2.) The steps taken to return the pilot flame to proper operation; and (3.) Date and duration of periods when the emission control device and/or the associated containment and collection equipment is not functioning to control VOC and HAP emissions. (II) Date and duration of visible emissions from the combustion device. (III) Upon removal of a combustion device which controls emissions from a dehydration unit, hourly records of temperature shall be taken from the reboiler still vent outlet and accumulated condensed liquids. (B) Owner/operator shall record and maintain records for fugitive emissions pursuant to Subsection (g) of these regulations. These records shall include the dates and results of all LDAR inspections performed pursuant to a facility or source's LDAR protocol and any corrective actions taken as a result of the required inspections. (C) Records of date, duration, and reason for emergency and/or blowdown tank usage shall be maintained pursuant to Subsection (c)(i)(C) of these regulations.	PAW requests the elimination of the requirement for recording a reason for absence of a pilot flame. Most pilots are monitored by telemetry systems that automatically record downtime. This requirement adds a significant amount of additional paper work. — P-2-34 Paragraph (III) is more onerous than permitting guidance and as stated above, and puts an existing source operator at a disadvantage to a new source operator. Please clarify the intent of the requirement to record hourly temperature from the reboiler still vent. This requirement is overly burdensome and has no clear benefit from the onerous recordkeeping. — P-2-35 Paragraph (C) PAW requests the removal of this requirement for recordkeeping related to emergency and/or blowdown tank usage. Chapter 1, section 5 will cover requirements for emergency tanks. Records are kept of blowdowns through blowdown/venting permits and this is a duplicative requirement. Based on the record-keeping the Division has received from these permits, the Division has stated that emissions from blowdown and venting are not a significant source of emissions and thus additional record keeping is overly burdensome. — P-2-36
(iii) Reporting. The owner or operator of each facility or source shall comply with all applicable reporting requirements as specified by this subsection. (A) The owner or operator shall provide the name and location of the facility or source that will be required to install a combustion device, replace equipment, or implement an LDAR Protocol by April 1, 2015. (B) Control Device and Equipment Installation	Replace "will be required" with "may be required". Consistent with comments above that evaluating 2013 production may not be representative and that a longer phase-in period is needed for the compliance date, this notification should be more of a "heads up" notice rather than a commitment notice. Date should also be based on a minimum of 6 months after the actual promulgation date of the rule. One year after promulgation is recommended. — P-2-37

P-2

Proposed Rule	Comments
Notification. The owner or operator of each facility or source subject to the requirements of these regulations shall submit a report to the Division thirty (30) days after the end of each calendar quarter containing the following, if applicable: (I) The number of pollution control devices or equipment installed; (II) Pollution control installation date, type of control, and equipment controlled; (III) Name and location of facility or source where controls are installed;	A quarterly notification is unreasonable and it isn't clear if the report requires only notification of equipment installed for that quarter or a running total of all equipment installed since the compliance date. At the very least this should be an annual report that could be rolled into annual NSPS, Subpart OOOO reports. This is an excessive administrative exercise that benefits no one especially when a follow-up annual notification is required in paragraph (D) P-2-38
(C) Pneumatic Device Installation Notification. The owner or operator of each facility or source subject to the requirements of these regulations shall submit a report to the Division thirty (30) days after the end of each calendar quarter containing the following, if applicable:	As stated above for paragraph B, pneumatic device installation notification should be no more than an annual report. For pneumatics this will be even more burdensome than paragraph (B) because of the number of devices affected. Quarterly notifications combined with follow-up annual notifications are overly burdensome. P-2-39
(I) The number, type, ~~and bleed rate~~ of pneumatic devices installed and date of installation; and (II) Name and location of facility or source where controls are installed.	Bleed rate isn't needed to be included in (I) since low bleeds are already required and intermittent vent have no continuous bleed rate. P-2-40
(D) The final notification of installation required under Subsections (B) and (C) above shall be submitted no later than January 31, 2016. (E) Control Device and Equipment Removal Notification. The owner or operator of each facility or source subject to the requirements of these regulations shall submit a demonstration to the Division for approval prior to removal of any pollution control device and equipment. This demonstration shall contain at a minimum:	While this is onerous as written, to demonstrate the burden of these proposed notification requirements, equipment installed in the fourth quarter would require both a quarterly notification and separate annual notification submitted on the same day. What benefit is it to WDEQ to submit two separate notifications (quarterly and annual) with identical information? P-2-41 In paragraph (II), 2013 production should be replaced to be consistent with our recommendation in (c)(ii)(A). P-2-42
(I) The average daily condensate/oil or gas production rate for the previous twelve (12) calendar months; (II) Actual emissions as determined by utilizing paragraph (I) above in replacement of 2013 production data, and the applicability determination for flashing in	In paragraph (i)(E)(II) The word "Actual" should be deleted. It should be noted that the methodology required to calculate dehydration unit emissions as outlined in subsection (d)(ii) does not give you "Actual" emissions. Not taking into account the use of a condenser and being bound by the maximum glycol circulation rate P-2-43

P-2

Proposed Rule	Comments
Subsection (c)(ii) of these regulations and/or dehydration units in Subsection (d)(ii) of these regulations; (III) Any additional supporting data used to calculate emissions, including but not limited to, any extended or composite hydrocarbon analysis utilized; and (IV) Name and location of facility or source where controls are proposed for removal. (F) Any facility or source subject to requirements of Subsection (g) of these regulations shall submit the LDAR Protocol prior to implementation of the protocol. (G) A certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. (H) The owner or operator shall submit notifications or reports as required in this subsection to the Division electronically through https://airimpact.wyo.gov or by hard copy to the Cheyenne Office and Lander Field Office. Contact information for the Cheyenne and Lander offices can be obtained at: http://deq.state.wy.us/.	of the pump in use, makes these calculations a "potential" even though the remainder of operating conditions are average actual conditions. A responsible official as defined in Chapter 6, section 3 is inappropriate for minor sources. A definition has been recommended above for responsible official that ties the definition to that in NSPS, Subpart OOOO in which the recently proposed revision allows for a lower level of management to serve in the role. PAW requests the Division extend the reporting requirements to identify affected sources. Depending on finalization of the rule change, the current date of April 1, 2015 may not allow for enough time to gather information and calculate emissions. Submittal of the report by June 30, 2015 will allow for operators to utilize the effort to prepare WDEQ emission inventories to calculate emissions and identify affected sources.
(i) Compliance. Compliance with Chapter 8, Section 6 of the WAQSR, does not relieve any owner or operator of a facility or source from the responsibility to comply with any other applicable requirements set forth in any federal or State law, rule or regulation, or in any permit.	

P-2-44

P-2-45

P-2

General Comments
• PAW is opposed to the limited time frame for implementation of controls, should they be required. As currently proposed, notifications are due by 4/1/2015, with controls required by 1/1/2016. Budget considerations as well as changes to operational practices, staffing levels, etc., cannot be handled in the time frame currently proposed. Even if sources are not required to install controls under this rule, significant effort and cost will be required to conduct the applicability analyses as well as comply with monitoring, recordkeeping and reporting requirements. This, in addition to the cost of installing control equipment, drives the need for a longer implementation time. **No less than a 3 year implementation timeframe should be allowed as done with federal NESHAP regulations for existing sources.** P-2-46
• Are blowdown tanks included in the emission limits? A strict reading of the definition of "storage tanks" makes us believe they are. However, in the September 2013 guidance does not include blowdown tank emissions under control requirements other than best management practices (BMPs), and the blowdown permits currently issued require the same. PAW believes blowdown tanks should be excluded from tank emission calculations. In addition, PAW requests that all other recordkeeping and control requirements relating to blowdown tanks be removed from the rule. Chapter 1, Section 5 covers emergency tank requirements. The requirements of the proposed rule provide insignificant environmental benefit and duplicate the requirements of the venting / blowdown permits. The Division has stated that emissions from blowdown and venting are not a significant source of emissions and thus, additional recordkeeping is overly burdensome. P-2-47
• It is unclear how this rule will impact the "Interim Permitting Policy for Sources in Sublette County". PAW requests that the DEQ explain whether this rule will eliminate the need for an offset program, of if not, an explanation is needed on how the rule and the offset policy will coexist. Specifically, if controls (combustors) are installed to limit VOC emissions, will this require additional NOx credits? It doesn't seem appropriate to require offset credits for NOx as a result of systems installed to reduce VOC emissions. Also, it will be very difficult to generate any type of VOC credits, making it virtually impossible for new operators to enter the area.How does WDEQ propose to handle this scenario? P-2-48
• Definitions should exactly match those already defined in the p-BACT guidance or Chapter 6, Section 3 definition of responsible official for major sources would be inappropriate for this rule, and needs to be defined appropriately for minor sources P-2-49

directed at the Board, because this is just a public comment, and so you ask us for clarifications, request for clarifications, but make all your comments directly to the Board.

And what I'm going to do is just go through in order of the sign-up and take your time, whatever you need to say, do it. And first one is Mr. John Robitaille from PAW.

MR. ROBITAILLE: Just step by you here.

Thank you, Mr. Chairman. John Robitaille, Petroleum Association of Wyoming.

P-2V-1

We submitted comments last week, and rather than spend the next two hours going through them, I think I will suggest that what we're proposing is that this Board not pass this rule at this time. We are suggesting that you remand it back to the Air Quality Division and allow us an opportunity to sit down with them and review our comments in a face-to-face meeting. I'd suggest to you that it would probably be able to be accomplished in a one-day meeting. May very well be a long day, but I believe that we can handle it all in one day.

I can tell you that we are not opposed to the rule. We are opposed to the rule as written. We believe there are some inconsistencies. We believe that there are some -- some ambiguities, and we are a little concerned

RECEIVED JUL 2014 AIR QUALITY DIVISION

July 11, 2014

TRANSMITTED BY FAX TO 307-777-5616

Steven A. Dietrich
Administrator, DEQ/AQD
Herschler Building 2-E
122 W. 25th Street
Cheyenne, WY 82002

Re: USQ Comments on Wyoming Air Quality Standards and Regulations for Nonattainment Area Regulations - Chapter 8, Section 6, Requirements for existing oil and gas production facilities or sources in the Upper Green River Basin

Dear Mr. Dietrich:

Thank you for the opportunity to comment on the proposed revisions to the Wyoming Air Quality Standards and Regulations (WAQSR) Chapter 8, Section 6. As described by our specific comments below, Ultra, Shell and QEP (USQ) have reviewed the proposed revisions and have a number of concerns. One overarching concern is that the timelines set forth in the proposed rule are not realistic for implementing the changes that would be required. In the case of one operator, the proposed rule would impact approximately 400 wells spread over about 20 multi-well pads. A phase-in approach, which would allow for incorporation of any new requirements, would be more appropriate. We would be happy to talk more with you about the level of effort and needed time allowances.

P-3-1

It is unclear how this rule relates to the Interim Policy on Demonstration of Compliance with WAQSR Chapter 6, Section 2(c)(ii) for Sources in Sublette County. Specifically, if existing NOx emission credits must be utilized to offset the NOx emissions increase resulting from the required VOC controls on existing sources. Or, if reducing VOC emissions due to the installation of additional VOC controls will generate VOC emission credits for the offset bank. The accounting of emission credits/offsets resulting from this rule should be worked through and clearly defined.

P-3-2

Where controls are added as a result of requirements associated with this rule, it is unclear how the control requirements will become federally enforceable without modifying the existing air quality permits to include additional permit conditions (e.g., specifics regarding monitoring control devices, record keeping, and inspections). Please clarify how the Wyoming Department of Environmental Quality (WDEQ) envisions this process working going forward.

P-3-3

USQ has implemented a number of measures to comply with JPAD-specific control requirements that are outlined in the WDEQ's "Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance". In many cases, emissions control measures have been implemented at existing pads where new wells were added. USQ does not believe that additional modification of those pads to bring them into compliance with the new rule is an effective use of resources. Therefore, USQ suggests that JPAD facilities with an existing permit that includes presumptive BACT requirements prepared according to the March 2010 or subsequent revision of the Permitting Guidance be exempt from the rule.

P-3-4

1.) *Section 6 (a) Applicability (i) states the following:*

"These regulations apply to all single well and multiple well pad oil and gas production facilities or sources and all associated production equipment located in the Upper Green River Basin (UGRB) ozone nonattainment area that were existing as of January 1, 2014."

Comment:

P-3-5

Please define "and all associated production equipment," as it could be interpreted to include production equipment not located at a well pad. If that is WDEQ's intent, please state more explicitly what is and is not included (e.g., compressor stations, central gathering facilities, etc.). If the term is interpreted to include these types of midstream facilities, the rule should be re-noticed and the midstream companies provided ample time to review and comment.

2.) *Section 6 (a) Applicability (i) states the following:*

"These regulations apply to all single well and multiple well pad oil and gas production facilities or sources and all associated production equipment located in the Upper Green River Basin (UGRB) ozone nonattainment area that were existing as of January 1, 2014.

Section 6 (a) Applicability (ii) states the following:

"A facility or source shall comply with all applicable requirements of these regulations unless a Wyoming Air Quality Standards and Regulations (WAQSR) Chapter 6, Section 2 permit has been issued, which must be as stringent or more stringent than the requirements of these regulations; .."

Section 6 (g) Fugitives (i) (A) states the following:

"(i) For facilities in existence prior to January 1, 2014, with fugitive emissions greater than or equal to 4 tpy of VOCs, operators shall implement a Leak Detection and Repair (LDAR) Protocol.

(A) The LDAR Protocol monitoring schedule shall be no less frequent than quarterly;"

Comment:

P-3-6

USQ is currently subject to periodic (e.g., semi-annual) LDAR monitoring requirements per their Chapter 6, Section 2 permits. Where the frequency of this monitoring is less stringent than the quarterly frequency proposed in Chapter 8, Section 6(g), they would no longer qualify under Section 6, (a), (ii) as having a permit which is as stringent, or more stringent than the requirements of these regulations. USQ sees no benefit to quarterly monitoring over semiannual. Rather, years of monitoring data demonstrate that semiannual monitoring is costly and unwarranted, and the frequency should be reduced to annual.

Operators routinely apply good operating practices (visual and olfactory detection, use of leak detection solutions [e.g. Snoop], and periodic monitoring with a gas detector) to identify and repair fugitive emissions from equipment leaks on an on-going basis at their facilities. Operators do not rely on LDAR programs as their sole means to identify and repair leaks. Rather, they use the information from LDAR surveys to confirm and demonstrate the effectiveness of our work practices and identify opportunities for improvement.

As a practical example, QEP has conducted eight Infrared (IR) LDAR surveys over the past five years of their Pinedale Anticline Development Area (PAPA) well pads. Their most recent monitoring program conducted in November 2013 included over 284,000 components at 637 wells on 28 pads (at the time this was an estimated 80% of the total QEP wells in the Pinedale field). Summaries of the eight semi-annual monitoring efforts are enclosed. The data collected to date demonstrate the following:

- The field-wide leak rate is consistently close to 0.1% (1 leak per 1,000 components),
- The 99% confidence interval leak rate is consistently below 0.2% (less than 2 leaks per 1,000 components),
- Leak rates are similar for all pads, regardless of whether they have been previously surveyed with an IR camera or not, and
- The leak rate does not vary depending on the interval between IR camera leak surveys.

The cost to implement the IR LDAR program is significant; the most recent survey conducted by QEP in November 2013 was completed at a cost of approximately $150,000. These costs have been and are expected to continue increasing with each subsequent survey, as more wells and pads are added to the program. USQ has estimated that the cost of an internal program to conduct quarterly LDAR inspections would be around $615,000 annually[1].

QEP has conducted multiple semi-annual LDAR inspections with minimal reduction in leakage rates. Over the five year monitoring history average leak rates have dropped from 0.08% to 0.06%, equating to one less leaking component per 5,000 components monitored. In addition, these inspections have shown that leakage rates are minimal and remain minimal. Therefore, it is not a forgone conclusion that an increased frequency of inspections will have a net environmental benefit, or meet the intent of this rule. **While USQ acknowledges the benefit of LDAR programs and inspections, evidence indicates that quarterly inspections do not contribute to greater emissions reductions than annual inspections. ~~In addition~~ testing twice as often brings not only increased cost to the operators, but doubles the amount of emissions generated by the crews themselves traveling to and from the locations and conducting the testing.** QEP's five years of semiannual monitoring data supports a **reduction** in monitoring frequency to **annual** rather than an increase in monitoring frequency to quarterly.

P-3-7

In addition, a reasonable timeframe should be established for the implementation of the LDAR plan. Time is needed to obtain facility component counts, calculate emissions, and arrange/schedule the surveys for affected facilities. The implementation date for this section should be January 1, 2016, or any modified timeline that is consistent with the remaining sections of the rule.

3.) Chapter 8, Section 6(g)(ii) Applicability Determination for Fugitive Emissions., (A)(I) states the following:

(A) Fugitive emissions shall be estimated using Table 2-4 from EPA-453/R-95-017, Protocol for Equipment Leak Emission Estimates, and the total facility component count.

(I) Facility Component Counts shall be determined by field actual count.

[1] Assumes 4 man crew @$70/hour ea. 2080 hours/yr cost of two cameras@$150,000 ea. over 4 years.

P-3-8

Comment: Determining actual field counts of facility components also requires extensive manual effort and is very costly. USQ does not believe that this will contribute notably to emissions reductions. USQ estimates that it would cost approximately $1,400[2] per well. USQ currently has more than 2300 wells in the UGRB, this would therefore, cost upwards of $3 million.

Rather than requiring actual total facility component counts at each facility as a basis for fugitive emission calculations, please consider allowing each company to utilize an actual component count from a limited number of representative facilities. The representative actual component counts would be used to estimate counts for all remaining facilities and associated equipment in the field. Either way, guidance will need to be provided, which clearly defines what components should be included.

Alternatively, please consider using current published and accepted component count methods listed in Part 98, Subpart W – Petroleum and Natural Gas Systems, specifically to 40 CFR §98.233(r) and Table W-1B. This method has already undergone the research, scrutiny, and public comment as required to be published in the Federal Register, and USQ believes this alternative method to determine component counts is appropriate for this application.

4.) *Chapter 8, Section6(g)(ii) Applicability Determination for Fugitive Emissions., (B) states the following:*

> (B) *Site-specific speciated hydrocarbon emission rates can be estimated by multiplying the total hydrocarbon emission rate estimated in Subsection (ii)(A) above by measured VOC and HAP weight fractions.*

P-3-9

Comment: To maintain consistency with permitted fugitive emissions and the emission inventory calculations, USQ would like to add the option to use the published speciated fugitive emission factors (C6 S2 O&G Production Facilities Permitting Guidance, Sept 2013, pg 70 of 76) in addition to using the option of measured weight fractions.

5.) *Chapter 8, Section 6(c) Flashing Emissions at an Existing Facility or Source as of January 1, 2014 section (i) (C) states the following:*

> *"(C) Emergency, open-top and/or blowdown tanks shall not be used as active storage tanks but may be used for temporary storage.*
>
> *... (II) If emergency, open-top and/or blowdown tanks are utilized, they must be emptied within seven (7) calendar days."*

P-3-10

Comment: There are several streams other than blowdowns routed to the blow tanks, such as dehy blowcases and fuel gas scrubbers, and the tank is used as a storage tank for these minor, low-emission streams. Also, the volume routed to the tank during well blowdowns is quite small. It seems unnecessary to require tanks to be emptied after 7 days, as most emissions are from flash and will have already occurred by that time.

6.) *Chapter 8, Section 6(d) Dehydration Units at an Existing Facility or Source as of January 1, 2014 section (i) (A) States the following:*

[2] Assumes 1 man crew @$70/hour. 2 – 10 hour days per well.

P-3

July 11, 2014
Mr. Dietrich
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"(A) PAD Facilities and Single Well Facilities. For total uncontrolled VOC emissions from all dehydration units that are greater than or equal to 4 tpy, VOC and HAP emissions from all dehydration units shall be controlled to at least 98% and equipped with reboiler still vent condensers by January 1, 2016.

P-3-11 **Question:** If combustors are installed on existing dehydration units to comply with the proposed regulation will NO_x offsets be required for the additional NO_x emissions generated? Will emission credits be granted for reducing VOC emissions? How will offsets be tracked? Based on recent conversations with DEQ Staff, USQ understands that the Interim policy will remain in place into at least 2015. This does not seem appropriate since we are installing this equipment to reduce VOC emissions. Can DEQ clarify their position on this?

P-3-12 – P-3-13 **Comment:** USQ suggests this section be reworded to require a control device with a destruction efficiency of at least 98%. (So that operators are not presumed to be out of compliance any time there is downtime, for example to conduct maintenance.) Also, what about existing facilities that are already equipped with control devices designed / required to achieve 95% destruction efficiency. Must they be replaced? Will operators be required to conduct stack tests to demonstrate they can achieve 98% control?

7.) **Chapter 8, *Section 6(d) Dehydration Units at an Existing Facility or Source as of January 1, 2014 section (ii) (C)(I) states that model input shall consist of the following:***

(I) A site-specific or composite extended hydrocarbon analysis of wet gas;

P-3-14 **Question:** Is the composite extended hydrocarbon analysis +/- 25 psig requirement based on wellhead pressure or separator pressure?

P-3-15 **Comment:** For the CY2013 emission inventories, the WDEQ changed the wet gas analyses used to calculate emissions from dehydration units. The large number of unique analyses provided to the Division was grouped together by field and formation characteristics from varying pressure profiles. Previously these analyses were grouped by separator pressure. To be consistent with how dehy emissions are calculated in the emission inventories, USQ requests the WDEQ consider removing +/- 25 psig requirement allow for "samples from at least five wells producing from the same field and formation" as meeting the composite analysis criteria.

USQ would also like to include the option to use the published WDEQ wet gas and liquid analyses for the emission calculations to maintain consistency with the calculated emissions in the existing permit and in the emission inventories.

8.) ***Chapter 8, Section 6(e) Existing Pneumatic Pumps as of January 1, 2014 part (i) states the following:***

"VOC and HAP emissions associated with the discharge streams of all natural gas-operated pneumatic pumps shall be controlled to at least 98% or the pump discharge streams shall be routed into a sales line, collection, fuel supply line or other closed loop system by January 1, 2016.

P-3-16 **Question:** Because there is an emissions control removal policy for sites with VOC emissions less than 4 tpy it is unclear whether this section applies to all sites, or only sites that are greater than 4 TPY. If emissions are currently below 4 tpy at a site, should a control device be implemented?

USQ suggests this section be reworded to require emissions to be routed to a control device with a destruction efficiency of at least 98%. (So that operators are not presumed to be out of compliance any time there is downtime, for example to conduct maintenance.) Also, what about existing facilities that are already equipped with control devices designed / required to achieve 95% destruction efficiency? Must they be replaced? Will operators be required to conduct stack tests to demonstrate they can achieve 98% control?

P-3-17 **Comment:** It is not technically or economically feasible for all Operators to route the discharge from natural gas-operated pneumatic methanol injection pumps to existing combustor controls, a sales line, collection, fuel supply line or other closed loop system. A number of pneumatic methanol pumps have been replaced with solar operated pumps as new wells are added to existing facilities. However, there are a large number of pneumatic methanol pumps in the field, and it would be extremely costly to replace all of these pneumatic pumps by January 1, 2016.

9.) Chapter 8, Section 6(f) Existing Pneumatic Controllers as of January 1, 2014 states the following:

"Natural gas operated pneumatic controller shall be low (less than 6 standard cubic feet per hour (scfh)) or no-bleed controllers or the controller discharge streams shall be routed into a sales line, collection, fuel supply line or other closed loop system by January 1, 2016."

P-3-18 **Comment:** There are a number of pneumatic controllers that are currently not tied into sales line, collection, fuel supply line or other closed loop systems. It would be incredibly costly if not impossible to add these controls to every site by January of 2016.

Currently this section has no relief emissions threshold for implementation of control measures on pneumatic devices. It is unclear whether the 4 VOC TPY threshold mentioned throughout this rule is meant to apply to this section. Without such a threshold it could potentially be cost prohibitive to install emissions controls on low production sites.

10.) Chapter 8, Section6 (h) Monitoring, Recordkeeping and Reporting (MRR)

P-3-19 **Comment(s):** (h)(I)(A) -- Please specify what needs to be monitored to ensure that the 98% control requirements are being met.

P-3-20 **Comment(s):** (h)(I)(B) -- Please define what the "maximum temperature differential" between the reboiler exhaust vapors and the condensed liquids. How is the "maximum" achieved or demonstrated to satisfy this requirement? Also, this does not seem to be a MRR requirement. Should this be moved to section (d)?

P-3-21 **Comment(s):** (h)(II)(A)(III) - Hourly temperature records seem excessive and add additional expense to install a continuous monitoring device. That said, it seems rare that dehy controls would ever be removed.

P-3-22 **Comment(s):** (h)(III)(A) -- identifying which equipment requires control, replacement, or LDAR as early as April 1, 2015 seems unrealistic pending when this rule is finalized.

P-3

Sincerely,

Brad Johnson

Brad Johnson
Senior VP
Operations
Ultra Resources, Inc.
304 Inverness Way South
Suite 295
Englewood, CO 80112

JJ Freeman

Justin Freeman
Technical Manager
Rockies Assets
Shell Exploration & Production
200 N Dairy Ashford
Houston, TX 77079

Joe Redman

Joe Redman
General Manager
Greater Green River Basin
QEP Resources
1050 17th Street
Suite 800
Denver, CO 80265

Infrared Leak Detection and Repair (IR LDAR) Survey History

Pad	Leak Rate							
	Nov-09	Nov-10	May-11	Nov-11	Jun-12	Oct-12	Jun-13	Nov-13
Pad #1	0.10%	0.19%	0.07%	0.14%	0.05%	0.03%	0.05%	0.08%
Pad #2	0.24%	0.03%	0.10%	0.13%	0.01%	0.04%	0.08%	0.00%
Pad #3		0.16%	0.13%	0.22%	0.22%	0.05%	0.08%	0.06%
Pad #4		0.22%	0.17%	0.13%	0.03%	0.01%	0.01%	0.03%
Pad #5		0.06%	0.05%	0.10%	0.08%	0.12%	0.08%	0.04%
Pad #6		0.04%	0.06%	0.06%	0.10%	0.12%	0.07%	0.06%
Pad #7		0.06%	0.07%	0.08%	0.06%	0.04%	0.00%	0.02%
Pad #8		0.02%	0.07%	0.08%	0.02%	0.02%	0.02%	0.07%
Pad #9		0.03%	0.06%	0.14%	0.06%	0.03%	0.01%	0.03%
Pad #10		0.05%	0.03%	0.09%	0.00%	0.06%	0.04%	0.03%
Pad #11		0.16%	0.08%	0.06%	0.07%	0.13%	0.05%	0.09%
Pad #12		0.10%	0.08%	0.31%	0.10%	0.15%	0.17%	0.03%
Pad #13		0.11%	0.15%	0.07%	0.05%	0.08%	0.04%	0.05%
Pad #14			0.10%	0.38%	0.04%	0.04%	0.04%	0.04%
Pad #15			0.09%	0.06%	0.00%	0.06%	0.04%	0.04%
Pad #16			0.13%	0.15%	0.06%	0.06%	0.09%	0.18%
Pad #17			0.03%	0.06%	0.06%	0.09%	0.06%	0.08%
Pad #18				0.16%	0.08%	0.16%	0.08%	0.05%
Pad #19				0.15%	0.10%	0.14%	0.11%	0.03%
Pad #20				0.00%	0.08%	0.03%	0.08%	0.00%
Pad #21				0.17%	0.06%	0.13%	0.07%	0.04%
Pad #23						0.03%	0.08%	0.02%
Pad #22						0.04%	0.09%	0.01%
Pad #24						0.09%	0.08%	0.09%
Pad #25							0.19%	0.05%
Pad #26							0.07%	0.17%
Pad #27							0.02%	0.06%
Pad #28								0.07%

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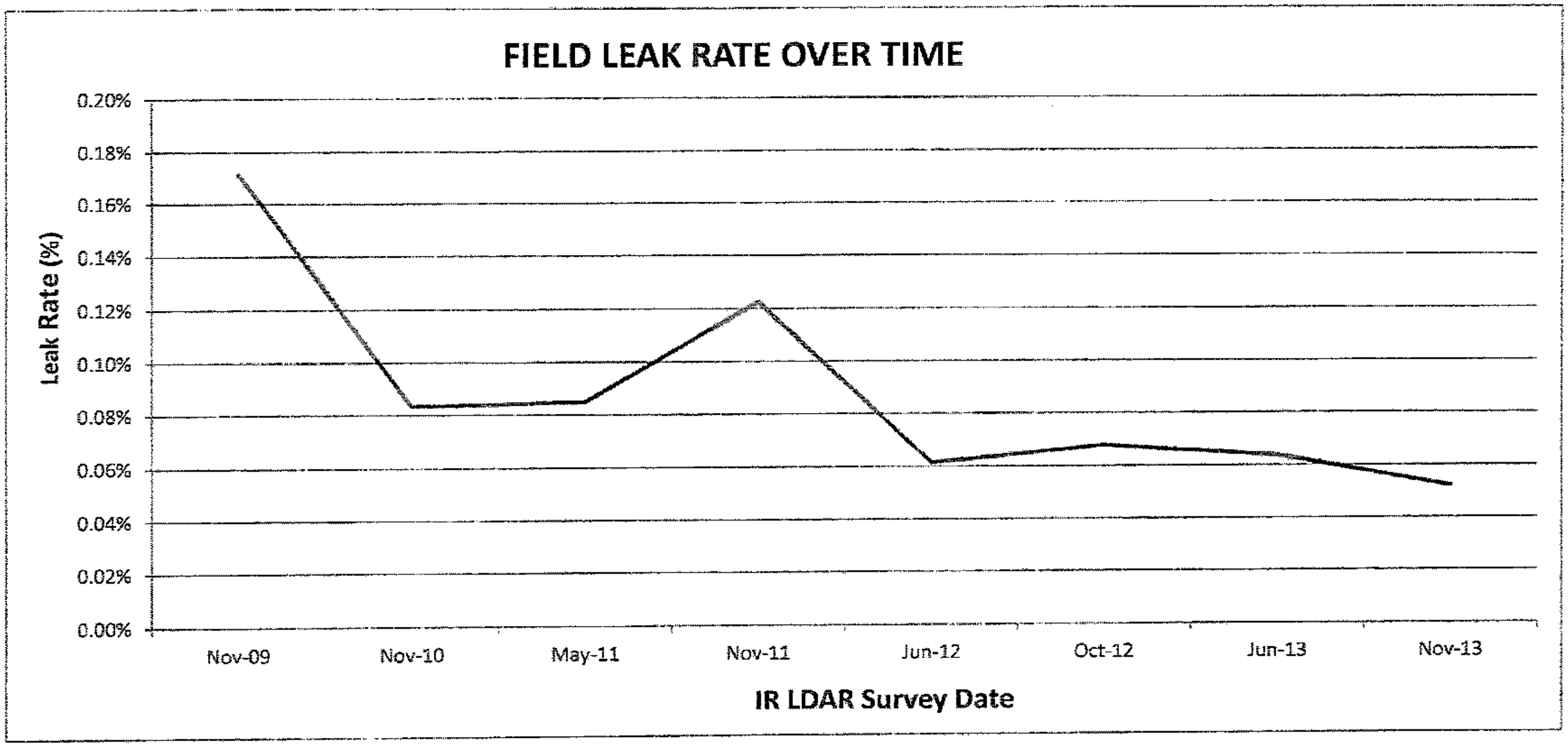
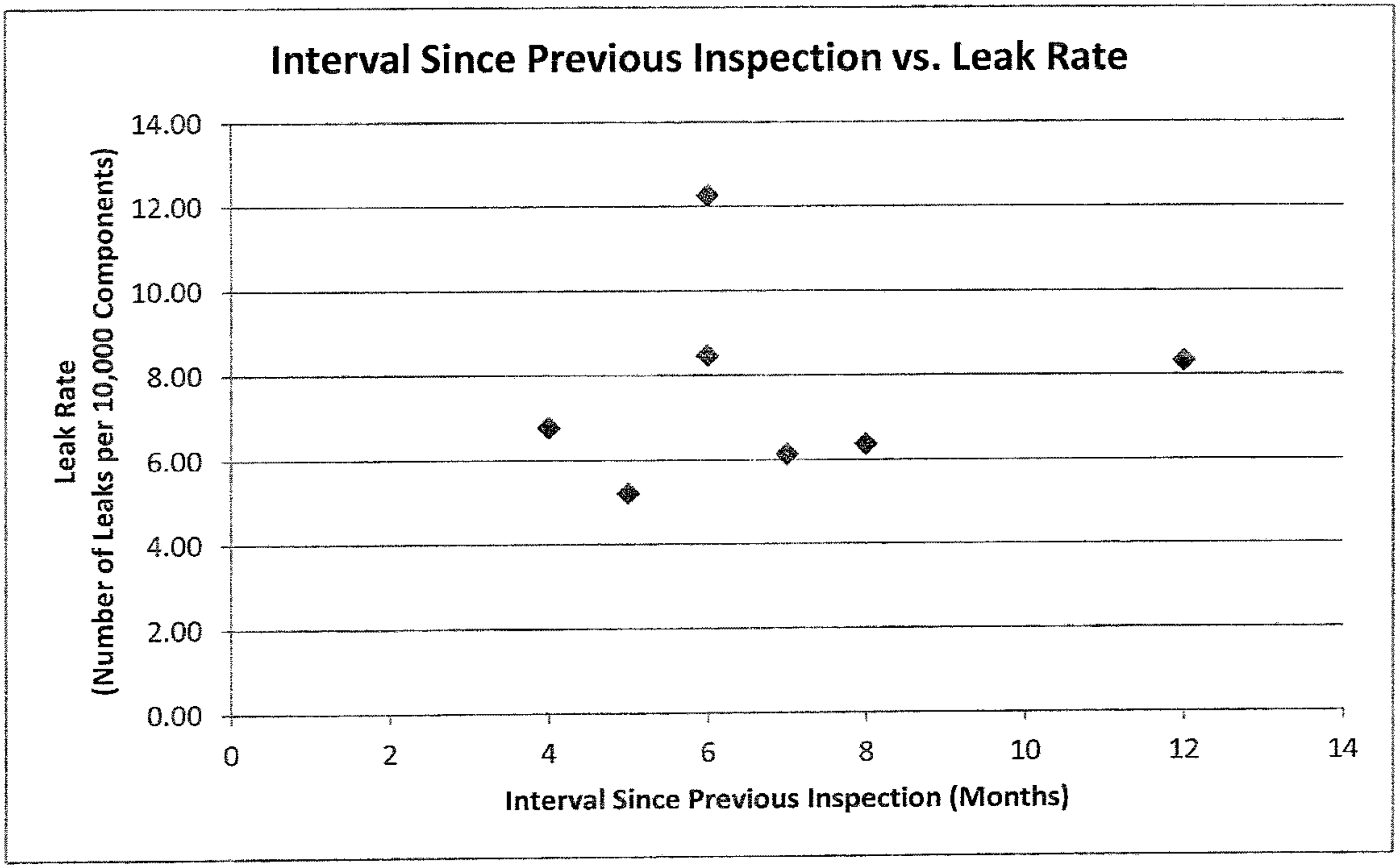
IR LDAR Field Survey Summary

SURVEY	INTERVAL SINCE PREVIOUS SURVEY (MONTHS)	# LEAKS	# COMPONENTS	LEAK RATE
Nov-09		51	29,735	0.17%
Nov-10	12	106	127,344	0.08%
May-11	6	118	139,412	0.08%
Nov-11	6	242	197,484	0.12%
Jun-12	7	121	197,484	0.06%
Oct-12	4	152	224,763	0.07%
Jun-13	8	170	267,361	0.06%
Nov-13	5	148	284,550	0.05%


FIELD LEAK RATE OVER TIME
Leak Rate (%)
0.20%
0.18%
0.16%
0.14%
0.12%
0.10%
0.08%
0.06%
0.04%
0.02%
0.00%
Nov-09
Nov-10
May-11
Nov-11
Jun-12
Oct-12
Jun-13
Nov-13
IR LDAR Survey Date


Interval Since Previous Inspection vs. Leak Rate
Leak Rate
(Number of Leaks per 10,000 Components)
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0
2
4
6
8
10
12
14
Interval Since Previous Inspection (Months)

P-3

November 2009 IR LDAR Survey

Pad	Leaks	# Components	Leak Rate	
Pad #1	16	15,275	0.10%	
Pad #2	35	14,460	0.24%	
TOTAL	**51**	**29,735**	**0.17%**	**FIELD-WIDE AVERAGE**

Number of Pads Sampled	2			
Degrees of Freedom (1-n)	1			
Average Leak Rate	0.173%			
Sample Standard Deviation	0.097%			
α (for 95% Confidence)	0.05			
$t_{\alpha/2}$	12.706	(for degrees of freedom = 1, $\alpha/2 = 0.025$)		
Average Leak Rate Between	-0.699%	and	1.046%	(95% confidence interval)

Small Sample 100(1-)% Confidence Interval
When Only the Sample Standard Deviation s is Known:
Mean ± $t_{\alpha/2}$ *s/sqrt(n)
n = sample size
s = sample standard deviation
$t_{\alpha/2}$ = t-value with an area of $\alpha/2$ to its right

November 2010 IR LDAR Survey

Pad	Leaks	# Components	Leak Rate	
Pad #1	17	9,057	0.19%	
Pad #2	6	20,006	0.03%	
Pad #3	19	11,557	0.16%	
Pad #4	9	4,133	0.22%	
Pad #5	5	8,273	0.06%	
Pad #6	4	10,320	0.04%	
Pad #7	5	8,273	0.06%	
Pad #8	3	13,876	0.02%	
Pad #9	2	7,965	0.03%	
Pad #10	6	11,767	0.05%	
Pad #11	20	12,314	0.16%	
Pad #12	4	4,133	0.10%	
Pad #13	6	5,670	0.11%	
TOTAL	**106**	**127,344**	**0.08%**	**FIELD-WIDE AVERAGE**

Number of Pads Sampled (n)	13			
Degrees of Freedom (n-1)	12			
Average Leak Rate	0.094%			
Sample Standard Deviation	0.068%			
α (for 95% Confidence)	0.05			
$t_{\alpha/2}$	2.179	(for degrees of freedom = 12, $\alpha/2$ = 0.025)		
Average Leak Rate Between	**0.053%**	and	**0.135%**	(95% confidence interval)

Number of Pads Sampled (n)	13			
Degrees of Freedom (n-1)	12			
Average Leak Rate	0.094%			
Sample Standard Deviation	0.068%			
α (for 99% Confidence)	0.01			
$t_{\alpha/2}$	3.055	(for degrees of freedom = 20, $\alpha/2$ = 0.005)		
Average Leak Rate Between	**0.037%**	and	**0.151%**	(99% confidence interval)

Small Sample α = (1-0.95) (for 95% Confidence Interval)
When Only the Sample Standard Deviation s is Known:
Mean $\pm\, t_{\alpha/2}$ *s/sqrt(n)
n = sample size
s = sample standard deviation
$t_{\alpha/2}$ = t-value with an area of $\alpha/2$ to its right

May 2011 IR LDAR Survey

P-3

Pad	Leaks	# Components	Leak Rate	
Pad #1	9	13,470	0.07%	
Pad #2	17	16,776	0.10%	
Pad #3	13	10,247	0.13%	
Pad #4	10	5,917	0.17%	
Pad #5	3	5,917	0.05%	
Pad #6	5	8,633	0.06%	
Pad #7	5	6,916	0.07%	
Pad #8	8	12,140	0.07%	
Pad #9	4	6,957	0.06%	
Pad #10	3	8,916	0.03%	
Pad #11	7	9,327	0.08%	
Pad #12	5	6,304	0.08%	
Pad #13	15	9,835	0.15%	
Pad #14	4	3,958	0.10%	
Pad #15	4	4,224	0.09%	
Pad #16	4	3,039	0.13%	
Pad #17	2	6,836	0.03%	
TOTAL	**118**	**139,412**	**0.08%**	**FIELD-WIDE AVERAGE**

Number of Pads Sampled (n)	15			
Degrees of Freedom (n-1)	16			
Average Leak Rate	0.086%			
Sample Standard Deviation	0.040%			
α (for 95% Confidence)	0.05			
$t_{\alpha/2}$	2.120	(for degrees of freedom = 16, $\alpha/2 = 0.025$)		
Average Leak Rate Between	**0.064%**	and	**0.108%**	(95% confidence interval)

Number of Pads Sampled (n)	17			
Degrees of Freedom (n-1)	16			
Average Leak Rate	0.086%			
Sample Standard Deviation	0.040%			
α (for 99% Confidence)	0.01			
$t_{\alpha/2}$	2.921	(for degrees of freedom = 20, $\alpha/2 = 0.005$)		
Average Leak Rate Between	**0.058%**	and	**0.115%**	(99% confidence interval)

Small Sample $\alpha = (1-0.95)$ (for 95% Confidence Interval)
When Only the Sample Standard Deviation s is Known:
Mean $\pm t_{\alpha/2}$ *s/sqrt(n)
n = sample size
s = sample standard deviation
$t_{\alpha/2}$ = t-value with an area of $\alpha/2$ to its right

November 2011 IR LDAR Survey

Pad	Leaks	# Components	Leak Rate	
Pad #1	26	18,546	0.14%	
Pad #2	27	20,006	0.13%	
Pad #3	25	11,557	0.22%	
Pad #4	9	7,008	0.13%	
Pad #5	8	8,273	0.10%	
Pad #6	6	10,247	0.06%	
Pad #7	7	8,273	0.08%	
Pad #8	14	16,936	0.08%	
Pad #9	11	7,965	0.14%	
Pad #10	10	11,709	0.09%	
Pad #11	7	12,314	0.06%	
Pad #12	13	4,133	0.31%	
Pad #13	8	11,347	0.07%	
Pad #14	17	4,462	0.38%	
Pad #15	3	4,784	0.06%	
Pad #16	5	3,375	0.15%	
Pad #17	5	7,844	0.06%	
Pad #18	10	6,193	0.16%	
Pad #19	11	7,280	0.15%	
Pad #20	0	3,697	0.00%	
Pad #21	20	11,535	0.17%	
TOTAL	**242**	**197,484**	**0.12%**	**FIELD-WIDE AVERAGE**

Number of Pads Sampled (n)	21			
Degrees of Freedom (n-1)	20			
Average Leak Rate	0.131%			
Sample Standard Deviation	0.088%			
α (for 95% Confidence)	0.05			
$t_{\alpha/2}$	2.086	(for degrees of freedom = 20, $\alpha/2 = 0.025$)		
Average Leak Rate Between	**0.091%**	and	**0.171%**	(95% confidence interval)

Number of Pads Sampled (n)	21			
Degrees of Freedom (n-1)	20			
Average Leak Rate	0.131%			
Sample Standard Deviation	0.088%			
α (for 99% Confidence)	0.01			
$t_{\alpha/2}$	2.845	(for degrees of freedom = 20, $\alpha/2 = 0.005$)		
Average Leak Rate Between	**0.076%**	and	**0.186%**	(99% confidence interval)

Small Sample $\alpha = (1-0.95)$ (for 95% Confidence Interval)
When Only the Sample Standard Deviation s is Known:
Mean $\pm t_{\alpha/2} * s/\text{sqrt}(n)$
n = sample size
s = sample standard deviation
$t_{\alpha/2}$ = t-value with an area of $\alpha/2$ to its right

Pad	Leaks	# Components	Leak Rate
Pad #1	10	18,546	0.05%
Pad #2	2	20,006	0.01%
Pad #3	26	11,557	0.22%
Pad #4	2	7,008	0.03%
Pad #5	7	8,273	0.08%
Pad #6	10	10,247	0.10%
Pad #7	5	8,273	0.06%
Pad #8	4	16,936	0.02%
Pad #9	5	7,965	0.06%
Pad #10	0	11,709	0.00%
Pad #11	9	12,314	0.07%
Pad #12	4	4,133	0.10%
Pad #13	6	11,347	0.05%
Pad #14	2	4,462	0.04%
Pad #15	0	4,784	0.00%
Pad #16	2	3,375	0.06%
Pad #17	5	7,844	0.06%
Pad #18	5	6,193	0.08%
Pad #19	7	7,280	0.10%
Pad #20	3	3,697	0.08%
Pad #21	7	11,535	0.06%
Totals	121	197484	0.06%

Number of Pads Sampled (n)	21			
Degrees of Freedom (n-1)	20			
Average Leak Rate	0.065%			
Sample Standard Deviation	0.047%			
α (for 95% Confidence)	0.05			
$t_{\alpha/2}$	2.086	(for degrees of freedom = 20, $\alpha/2$ = 0.025)		
Average Leak Rate Between	0.043%	and	0.086%	(95% confidence interval)

Number of Pads Sampled (n)	21			
Degrees of Freedom (n-1)	20			
Average Leak Rate	0.065%			
Sample Standard Deviation	0.047%			
α (for 99% Confidence)	0.01			
$t_{\alpha/2}$	2.845	(for degrees of freedom = 20, $\alpha/2$ = 0.005)		
Average Leak Rate Between	0.035%	and	0.094%	(99% confidence interval)

Small Sample α = (1-0.95) (for 95% Confidence Interval)

When Only the Sample Standard Deviation s is Known:

Mean $\pm$ $t_{\alpha/2}$ *s/sqrt(n)

n = sample size

s = sample standard deviation

$t_{\alpha/2}$ = t-value with an area of $\alpha/2$ to its right

October 2012 IR LDAR Survey

P-3

Pad	Leaks	# Components	Leak Rate	
Pad #1	6	18,546	0.03%	
Pad #2	8	20,006	0.04%	
Pad #3	6	11,557	0.05%	
Pad #4	1	7,008	0.01%	
Pad #5	10	8,273	0.12%	
Pad #6	12	10,247	0.12%	
Pad #7	3	8,273	0.04%	
Pad #8	3	16,936	0.02%	
Pad #9	2	7,965	0.03%	
Pad #10	7	11,709	0.06%	
Pad #11	16	12,314	0.13%	
Pad #12	6	4,133	0.15%	
Pad #13	9	11,347	0.08%	
Pad #14	2	4,462	0.04%	
Pad #15	3	4,784	0.06%	
Pad #16	2	3,375	0.06%	
Pad #17	7	7,844	0.09%	
Pad #18	10	6,193	0.16%	
Pad #19	10	7,280	0.14%	
Pad #20	1	3,697	0.03%	
Pad #21	15	11,535	0.13%	
Pad #22	3	7,523	0.04%	
Pad #23	4	13,321	0.03%	
Pad #24	6	6,435	0.09%	
TOTAL	**152**	**224,763**	**0.07%**	**FIELD-WIDE AVERAGE**

Number of Pads Sampled (n)	24			
Degrees of Freedom (n-1)	23			
Average Leak Rate	0.073%			
Sample Standard Deviation	0.046%			
α (for 95% Confidence)	0.05			
$t_{\alpha/2}$	2.086	(for degrees of freedom = 20, $\alpha/2$ = 0.025)		
Average Leak Rate Between	0.053%	and	0.092%	(95% confidence interval)

Number of Pads Sampled (n)	24			
Degrees of Freedom (n-1)	23			
Average Leak Rate	0.073%			
Sample Standard Deviation	0.046%			
α (for 99% Confidence)	0.01			
$t_{\alpha/2}$	2.845	(for degrees of freedom = 20, $\alpha/2$ = 0.005)		
Average Leak Rate Between	0.046%	and	0.099%	(99% confidence interval)

Small Sample $\alpha = (1-0.95)$ (for 95% Confidence Interval)
When Only the Sample Standard Deviation s is Known:
Mean $\pm\, t_{\alpha/2} * s/\mathrm{sqrt}(n)$
n = sample size
s = sample standard deviation
$t_{\alpha/2}$ = t-value with an area of $\alpha/2$ to its right

P-3

Pad	Leaks	# Components	Leak Rate
Pad #1	10	18546	0.05%
Pad #2	16	20006	0.08%
Pad #3	12	15731	0.08%
Pad #4	1	7008	0.01%
Pad #5	13	15833	0.08%
Pad #6	8	11841	0.07%
Pad #7	0	8273	0.00%
Pad #8	3	16936	0.02%
Pad #9	1	7965	0.01%
Pad #10	5	11709	0.04%
Pad #11	6	12314	0.05%
Pad #12	7	4133	0.17%
Pad #13	4	11347	0.04%
Pad #14	2	4462	0.04%
Pad #15	2	4784	0.04%
Pad #16	3	3375	0.09%
Pad #17	5	7844	0.06%
Pad #18	5	6193	0.08%
Pad #19	8	7280	0.11%
Pad #20	3	3686	0.08%
Pad #21	9	13594	0.07%
Pad #22	7	7491	0.09%
Pad #23	10	13270	0.08%
Pad #24	9	11979	0.08%
Pad #25	15	7761	0.19%
Pad #26	4	5973	0.07%
Pad #27	2	8027	0.02%
TOTAL	**170**	**267,361**	**0.06%** **FIELD-WIDE AVERAGE**

Number of Pads Sampled (n)	27			
Degrees of Freedom (n-1)	26			
Average Leak Rate	0.067%			
Sample Standard Deviation	0.043%			
α (for 95% Confidence)	0.05			
$t_{\alpha/2}$	2.086	(for degrees of freedom = 20, $\alpha/2 = 0.025$)		
Average Leak Rate Between	**0.050%**	and	**0.084%**	(95% confidence interval)

Number of Pads Sampled (n)	27			
Degrees of Freedom (n-1)	26			
Average Leak Rate	0.067%			
Sample Standard Deviation	0.043%			
α (for 99% Confidence)	0.01			
$t_{\alpha/2}$	2.845	(for degrees of freedom = 20, $\alpha/2 = 0.005$)		
Average Leak Rate Between	**0.043%**	and	**0.090%**	(99% confidence interval)

Small Sample $\alpha = (1-0.95)$ (for 95% Confidence Interval)
When Only the Sample Standard Deviation s is Known:
Mean $\pm\ t_{\alpha/2} * s/\text{sqrt}(n)$
n = sample size
s = sample standard deviation
$t_{\alpha/2}$ = t-value with an area of $\alpha/2$ to its right

Pad	Leaks	# Components	Leak Rate
Pad #1	14	18546	0.08%
Pad #2	1	20006	0.00%
Pad #3	10	15731	0.06%
Pad #4	2	7008	0.03%
Pad #5	7	15833	0.04%
Pad #6	7	11841	0.06%
Pad #7	2	8273	0.02%
Pad #8	12	16936	0.07%
Pad #9	2	7965	0.03%
Pad #10	4	11709	0.03%
Pad #11	11	12314	0.09%
Pad #12	2	7189	0.03%
Pad #13	6	11347	0.05%
Pad #14	2	4462	0.04%
Pad #15	2	4784	0.04%
Pad #16	6	3375	0.18%
Pad #17	6	7844	0.08%
Pad #18	3	6193	0.05%
Pad #19	2	7280	0.03%
Pad #20	0	3686	0.00%
Pad #21	5	13594	0.04%
Pad #22	1	7491	0.01%
Pad #23	2	13270	0.02%
Pad #24	11	11979	0.09%
Pad #25	5	10813	0.05%
Pad #26	10	5973	0.17%
Pad #27	5	8027	0.06%
Pad #28	8	11081	0.07%
TOTAL	**148**	**284,550**	**0.05%** **FIELD-WIDE AVERAGE**

Number of Pads Sampled (n)	28			
Degrees of Freedom (n-1)	27			
Average Leak Rate	0.054%			
Sample Standard Deviation	0.041%			
α (for 95% Confidence)	0.05			
$t_{\alpha/2}$	2.086	(for degrees of freedom = 20, $\alpha/2$ = 0.025)		
Average Leak Rate Between	**0.038%**	and	**0.071%**	(95% confidence interval)

Number of Pads Sampled (n)	28			
Degrees of Freedom (n-1)	27			
Average Leak Rate	0.054%			
Sample Standard Deviation	0.041%			
α (for 99% Confidence)	0.01			
$t_{\alpha/2}$	2.845	(for degrees of freedom = 20, $\alpha/2$ = 0.005)		
Average Leak Rate Between	**0.032%**	and	**0.077%**	(99% confidence interval)

Small Sample α = (1-0.95) (for 95% Confidence Interval)
When Only the Sample Standard Deviation s is Known:
Mean ± $t_{\alpha/2}$ *s/sqrt(n)
n = sample size
s = sample standard deviation
$t_{\alpha/2}$ = t-value with an area of $\alpha/2$ to its right