April 17, 2026

James Thum
Idaho Department of Lands
Via Electronic Mail: Jthum@idl.idaho.com

Re: Drilling Permit for Proposed Miller 1-15 Gas/Oil Well

Dear Mr. Thum,

This firm represents Citizens Allied for Integrity and Accountability (CAIA) which is a membership organization that represents the interests of numerous residents of southwest Idaho, including mineral owners whose hydrocarbons will be recovered and sold by Snake River Oil and Gas (SROG or applicant) against their wishes. CAIA's members include Charlene Gomez, Darleen Walker, Sharon Harmon, Doris Craig, Larry Morris, Julie Fugate and John Sandquist, who live in the spacing unit in which the Miller 1-15 is proposed.

Even these individuals, who SROG would claim are in some fashion "helped" by receiving 12.5% of the value of their property in exchange for being compelled to sell it, have serious and compelling reasons to oppose this permit application. Many of them also live within close proximity to the well site for which SROG seeks a permit and will be directly affected by the excessive noise, pollution, and disruption that a drilling rig will necessarily bring to a residential neighborhood.

CAIA urges the Idaho Department of Lands and Idaho Oil and Gas Conservation Commission to address significant risks presented by Snake River Oil and Gas's proposed Miller 1-15 oil and gas well to be drilled on a segment of Payette County land located in the center of Fruitland City. While previous Payette County drilling operations have focused, for the most part, on remote areas of the foothills or tracts of land that were still relatively rural in character, SROG clearly has thrown all caution to the wind with this egregious application.

The company couldn't have chosen a more precarious location to perform volatile hydrocarbon production than this narrow strip of land, which lies directly adjacent to high density residential subdivisions, mobile home parks and individual homes numbering in the hundreds supported by a similar count of domestic water wells (See Attachment 1, list of wells within the likely impact area of the proposed Miller 1-15), and public irrigation

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ditches and nearly 150 businesses (See Attachment 2, list of local businesses within 1 mile of the proposed well stie).

Hundreds of these residences and businesses, including dozens of medical facilities, hospice centers, assisted living centers, daycares, preschools and churches, are located within the documented 1 mile or less 'threat radius' - established through scientific research by EPA, NIEHS and various universities - that surround oil and gas sites. (Attachment 3, list of scientific and regulatory reviews demonstrating a public health "threat radius" associated with hydrocarbon well sites/drilling). This threat exists whether extraction occurs through conventional drilling, acidizing or fracking.

Peer reviewed studies as well as direct observations have shown significantly higher concentrations of particulate matter (PM2.5), carbon monoxide, nitrous oxide, and ozone within two miles of pre-production wells (wells that have not been completed for production). For active wells, studies found spiked PM2.5, nitrous oxide, and volatile organic compounds emissions within 0.6 miles of the production sites, and higher ozone concentrations between 0.6 and 1.2 miles from the wells. (Att. 3, and sources cited therein).

This places thousands of citizens in Fruitland at elevated risk of mortality from brain, bladder, lung and breast cancers, severe respiratory issues, adverse birth outcomes, cardiovascular problems and other serious health issues due to benzene and other VOCs that are deliberately flared or vented off, or unintentionally and illegally leaked from oil and gas sites. Children living within this threat radius exhibit a 4 - 7 time higher risk of developing lymphoma or leukemia compared to those living further away. Likewise, elderly people living within close proximity to these heavy industrial operations experience higher cancer risks and increased mortality from a host of industry induced medical conditions. (Att. 3, and sources cited therein).

In late 2023 CAIA partnered with a certified ITC thermographer from Earthworks to perform FLIR optical gas imaging of SROG's oil and gas facilities across Payette County. The process exposed illegal emissions through venting, leaking and incomplete flares from multiple sources at their operations. Through follow-up actions CAIA learned that IDEQ – who is named as the state agency charged with regulating air quality in oil and gas matters – actually only handles permitting and paperwork they are given by operators but has no real authority to police the industry beyond that. In November of 2023 however, CAIA obtained EPA records (Attachments 4, 5, 6, 7) demonstrating that SROG and its corporate predecessors and partners Alta Mesa Idaho and Northwest Gas Processing had received repeated Notices of Violation from the federal agency for allowing illegal hazardous emissions to spew from their existing oil and gas operations on Little Willow Rd. and across Payette County for at least the last decade. Rather than admit to the violations and take responsibility for correcting the problem, SROG CEO Richard Brown denied in media reports that they were from his operations while state regulators tried to smooth over the facts by claiming that no problems had turned up in their own inspections of the facilities. Since that time there has been no evidence

published to show that state or federal regulators have taken any action to initiate compliance or hold the industry accountable. In light of that, CAIA asserts that this company has demonstrated they ***cannot*** be trusted to operate so perilously close to vulnerable human populations. Furthermore, by locating the drill site on this small sliver of county land in the center of Fruitland city SROG has deliberately and willfully circumvented the city's stricter drilling regulations designed to protect public and private property as well as the health and safety of citizens exposed to irresponsible oil and gas operations. This application seeks to weaponize legal jurisdiction specifically to avoid government oversight of highly hazardous activities.

Although IDL approved SROG's integration application for this proposed well - based largely on OAH Judge Scott Zanzig's order recommending integration – it is important to note that with his endorsement the judge also highlighted the limited scope of his authority, pointing out that the administrative proceeding was confined to determining if SROG had met the requirements to obtain an integration order, but that it did not determine whether or where any potential drilling operations may occur, or what restrictions may be placed on the operations. In fact, Judge Zanzig acknowledged that while the majority of the public comments expressing concern about risks to public health and safety were sincere and valid, given the potential drilling operations and their location, they did not affect a determination under statute as to whether IDL must issue the integration order. He further stated that SROG would still need to apply for and be approved to drill in that location and that the approval process would be the only opportunity for the citizens of Idaho to address the safety risks posed by for-profit operations by an industry that has already violated Idaho law in drilling and operating wells.

With that in mind CAIA urges the commission to consider the following when determining whether to approve this application.

I. Legal Standards

Idaho Administrative Code IDAPA 20.07.02.200 lists the scant few reasons for which an application to drill may be denied:

05. **Permit Denial.** Applications may be denied for the following reasons:

a. Application fee was not submitted.
b. Application is incomplete.
c. Failure to post required bonds.
d. Proposed well will result in a waste of oil or gas, a violation of correlative rights, or the pollution of fresh water supplies.

CAIA submits that permitting drilling in this planned location will likely violate all 3 of the highlighted conditions. Let's examine them in order:

<u>Wasting Oil or Gas</u> (per Idaho Statute)

9. Under the Act, the OGCC, through IDL as its administrative instrumentality, has the authority and duty to "regulate the exploration for and production of oil and gas, to prevent waste of oil and gas, [and] to protect correlative rights." I.C. §§ 47-314(6), 47-315(1). **10. Prevention of waste is paramount under the Act. I.C. § 47-315(1).** As it relates to gas production, waste is defined as "production of gas in quantities or in such manner as will unreasonably reduce reservoir pressure or unreasonably diminish the quantity of oil and gas that might ultimately be produced." I.C. § 47-310(36)(a).

Violating Correlative Rights (per Idaho Statute)

11. **A correlative right is defined as "the opportunity of each owner in a pool to produce his just and equitable share of oil and gas in a pool without waste." I.C. § 47-310(8).** 12. The Act requires IDL to regulate oil and gas development "in such a manner as to avoid the drilling of unnecessary wells or incurring unnecessary expense and in a manner that allows all operators and royalty owners a fair and just opportunity for production and the right to recover, receive and enjoy the benefits of oil and gas . . . while also protecting the rights of surface owners." I.C. § 47-315(2)

Allowing ongoing flaring and fugitive emissions from oil and gas operations - as this company and their former operating partner have done for over a decade - not only exposes citizens to toxic chemicals which can cause the aforementioned human health issues and increased mortality, but it is also a ***blatant waste of resources that costs property owners and taxpayers royalties they are legally entitled to***. As the attached reports confirm, billions of dollars are lost each year across oil and gas producing states due to the uncontrolled and illegal release of these hazardous, climate disrupting chemicals merely because the industry doesn't want to spend the money to follow safety regulations and too many public officials are influenced to look the other way (See Attachments 8, 9, 10). Permitting yet another, far more dangerous well for a company that for years has failed to take responsibility for toxic emissions generated by their existing facilities here would be an appalling corporate and regulatory failure.

Pollution of Fresh Water Supplies (per Idaho statute)

Idaho oil and gas laws administered primarily by IDL under IDAPA 20.07.02 require strict protection of freshwater, including mandatory groundwater monitoring, casing requirements, pit liners and plugging procedures to prevent contamination. Those regulations are intended to ensure that drilling activities do not contaminate aquifers by requiring identification of water zones, proper waste management, and mandatory reporting of potential pollution.

Drilling permits require, under Idaho Code 47-316, that the Idaho Department of Water Resources reviews applications, recommends conditions to protect freshwater and performs annual inspections of well sites and facilities to ensure compliance. While this appears sound at first glance the reality is that the deliberately short 10 day window allowed for department review of drilling applications can be wholly inadequate for

complex, high pressure "wildcat'' operations as most of the Payette County operations have been labeled.

Furthermore, records verifying that the proper inspections and enforcement are carried out in an effort to protect freshwater resources can be difficult or impossible for the general public to obtain. The veil of secrecy over oil and gas operations is a common roadblock for citizens trying to protect their communities.

II. Bases to Deny or Impose Conditions on the Permit

Through a public records request filed several years ago CAIA obtained the 1 and only wastewater report that officials confirmed has ever been recorded here in 16 years of modern oil and gas drilling operations. The sample came from AMI wells which are now owned entirely by SROG in Payette County. That report shows clear petroleum contamination (See Attachment 11). The known blood and bone carcinogen Benzene was reported at 4,280 µg/L, approximately 856 times EPA's maximum contaminant level for public drinking water (5 µg/L), and the neurotoxin toluene was reported at 4,150 µg/L, about 4.15 times EPA's drinking-water MCL (1,000 µg/L). The sample also contained ethylbenzene, total xylenes, methane, and ethane. Although ethylbenzene and xylenes in this particular sample were below EPA's federal drinking-water MCLs, their presence together with benzene, toluene, methane, and ethane is consistent with petroleum - and gas - related hazardous waste contamination.

We know that these same operators have injected dangerous chemicals underground and through our drinking water aquifers to 'acidize' some of the Payette County wells – and they did it illegally by sidestepping the very rules and laws the state claims are in place to protect freshwater sources (Attachments 12, 13). While state regulators did finally charge the company - 7 months *after* the incident – their punishment was a requirement to simply submit the proper permits retroactively and pay a fraction of the fines originally proposed. Eventually all record of their 'crime'' was removed from the state website, despite the company's public admission that it had violated Idaho law.

Scientific studies show that about 6% of oil and gas wells leak when initially drilled and that over time close to half of them end up leaking and potentially contaminating water sources – whether those wells were drilled conventionally or unconventionally. These official documents from the Pennsylvania Department of Environmental Protection (Attachments, 14, 15, 16) demonstrate the notable frequency with which domestic water wells have been contaminated by drilling in hundreds of both conventionally and unconventionally drilled wells across Pennsylvania. It has been well documented that faulty casing and cementing cause most well integrity problems. Steel casings can leak at the connections or corrode from acids. Cement can deteriorate with time too, but leaks also happen when cement shrinks, develops cracks or channels, or is lost into the surrounding rock when applied. If integrity fails, gases and liquids can and all too often do leak out of the casing or, just as importantly, move into, up, and out of the well through faulty cement between the casing and the rock wall allowing toxic drilling

chemicals and methane to contaminate water sources. Nothing in SROG's application demonstrates that it intends to take serious steps to avoid these well-known failures with traditional casing techniques.

Due to the number and density of domestic wells immediately surrounding the proposed Miller 1-15, the Administrator should impose the very highest possible standard for casing and protection of surrounding water resources. SROG should be required to comply with the American Petroleum Institute's latest specifications for surface casing known as API 5CT which was updated in 2025. The API standards for "wildcat" wells and for treatments are expressly called out in IDAPA 20.07.02.310. The API standards are not universally available to the public, instead being sold by subscription by API. It is the job of the Administrator to ensure that SROG's drilling, casing, cementing, BOP and operating plans all comply with API standards. Nothing in the application demonstrates that those standards are met.

There is only one method for ensuring that domestic water wells do not fall victim to shoddy drilling, casing, or treatment practices such as those that have already occurred in Payette County. That method is to test all domestic wells within a reasonable distance of the new gas well over time to create a baseline against which future samples can be tested. Such testing is expensive, and far exceeds what tiny royalties the integrated owners will be receiving. Such testing can easily cost $1,500 per well. (Attachment 17). In order to protect correlative rights, and to minimize the costs imposed on unwilling mineral rights owners in this spacing unit, the operator should be required to provide baseline water tests, as well as baseline health screening including blood tests for these families before they begin potentially drinking and bathing in the products of industrial drilling, or breathing cancer-causing VOC's in the air surrounding their homes. Without such a requirement, the drill permit would impose excessive costs on mineral owners, children, and members of the public, all in violation of I.C. §47-310. In addition, the risk of groundwater pollution is so high that requiring regular and extensive monitoring is the only way to ensure that this application complies with 47-310.

Yet another challenge with this application is the public irrigation ditch which runs partially on the Miller 1-15 property. IDAPA 20.07.02.310 calls for at least a 300 foot setback from drilling for canals, ditches and other water features, yet allows an exception to that rule by reducing the setback to 100 feet if the owner of the land where drilling will take place gives their permission. However, such a setback is inadequate as a matter of public health, as a method of protecting ground water, or as a method of protecting correlative rights and reducing the costs to integrated owners. The risks inherent in a public ditch (as opposed to, for instance a private and purely on-premises irrigation system) are too significant to be satisfied with "off the rack" solutions.

Furthermore, there is no evidence that SROG has created the type of spill containment and response plan that is required by well-established federal. In Title 40 Sections 112.01-21 provide standards and requirements for all oil and gas wells. Those Sections, and specifically 40 CFR 112.07, can only be met by preparing and publishing a plan for

spill prevention and recovery. No such plan is known to exist in this case. It would be inappropriate for Idaho to approve a drill permit that has not met the requirements of federal law. Indeed, the failure to comply with federal law renders compliance with state law irrelevant as the Environmental Protection Act and related federal provisions will always govern over lower state law standards.

III. Conclusion

While Idaho has determined that there is a public interest in gas development, the public interest in protecting Idaho's water resources which every citizen relies on are of far greater import. Please do not prioritize industry profits over the rights of Fruitland residents to enjoy a safe and peaceful existence in what for most people is their greatest life investment. Oil and gas extraction, whether achieved conventionally or through hazardous chemical processes like acidizing or fracking, has no place in high density residential neighborhoods.

Those specific objections are addressed by the statutory and regulatory reequipments that the permit must either be denied of have conditions placed on it that will prevent water pollution, or lead to "waste," or violate correlative rights. SROG's prior conduct, as well as the current drilling plan, demonstrate that SROG intends to create significant risks of water, air, noise and light pollution. SROG has a history of venting gas, constituting waste under the relevant standard, and any permit issued should explicitly prohibit any venting of hydrocarbons in the middle of a residential neighborhood. The drilling permit, by not including adequate pollution/contamination prevention and monitoring systems will impose excessive costs on mineral owners. Those cost should be borne by the operator/applicant as to do otherwise would violate correlative rights in violation of Idaho law. Deny this application or impose conditions that will guarantee full compliance with Idaho law.

Sincerely,

/s/*James M. Piotrowski*

James M. Piotrowski

175 IDWR recorded domestic water wells within 0.25 mile, 0.5 mile, 1 mile and 1.5 mile radius of the Miller 1-15 drilling site.
**Note these records do not include an existing number of domestic wells that were also drilled within this area prior to when the agency began recording well logs in 1987.*

0.25 Mile from proposed Miller 1-15 site

381349 Section 15 Harold Curt
356891 Section 15 Robert W. Wilson
294158 Section 15 Donald Boyd
293866 Section 15 Donald Boyd
293193 Section 15 Donald Boyd
443553 Section 15 Dickinson Frozen Foods
473398 Section 15 Dickinson "
436789 Section 15 Dickinson "
481100 Section 15 Dickinson "
353617 Section 15 Winston Alftin
371252 Section 15 John Sandquist
293308 Section 15 John Sandquist
470831 Section 14 Ry West Homes
409593 Section 14 Jeffery Rice
409046 Section 14 Art Lynch
468733 Section 14 Keith Clow
405753 Section 14 Art Lynch
455853 Section 14 Kenn Schappert
480771 Section 14 Paradise Building Co
405495 Section 14 Albert E Smith
414525 Section 22 Brian Cortright
389053 Section 22 City of Fruitland
389042 "
289663 Section 22 Gem Mobile Home Park LLC
289696 Section 22 City of Fruitland
293618 Section 22 J D Welsh & Assoc. Inc
293629 "
293630 "
398684 Section 22 Woodgrain Millwork Inc
396592 "
394602 "
394601 "
386820 "
398682 "
398681 "

398680 “
398679 “
394607 “
394605 “
394603 “
398689 “
398688 “
398687 “
398686 “
398685 “
394600 “
394599 “
394598 “
394597 “
386867 Section 22 Chevron
406749 Section 22 Fruitland Chevron
445440 Section 22 Tesoro Logistics Operations LLC

Total 52

0.5 Mile from proposed Miller 1-15 site

435595 Section 15 Troy Odell
455796 Section 15 Ben Musser
460942 Section 15 Ben Musser
292465 Douglas Dorsing
391612 Section 15 Veryl Neill
388316 Section 15 Louis Yturri
377072 Section 22 Ralph Edwards
345891 Section 22 Lewis Brockus
293909 Section 22 Leroy Chase
293908 Section 22 Leroy Chase
293681 Section 22 Chevron Oil Co
379614 Section 14 Irvin Dale Lish
362096 Section 14 Bill Odell
343298 Section 14 Dorothy D Salgado
293608 Section 14 Bud Dame
292801 Section 14 Dora E Scott
291520 Section 14 Dave Parks
290496 Section 14 George Tucker
289710 Section 14 Tom Yokum
289692 Section 14 Tom Yokum

388312 Section 22 Treasure Valley Bank
292713 Section 22 Fearless Farris Corp
292712 “
292711 “
292710 “
371253 Section 15 Omar M Hovde
459776 Section 22 Fearless Farris Corp
459777 “
459786 “
459779 “
459792 “
411680 Section 15 Forrest Flake
401948 Section 15 Dickinson Frozen Foods
376950 Section 15 Wayne Read
292761 Section 15 CH2M Hill
292760 “
292759 “
292132 “
292131 “
292130 “
292129 “
292128 “
292127 “
292126 “
292125 “
292124 “
292123 “
292122 “
292121 “
292120 “
292119 “
292118 “
292117 “
292116 “
292115 “
292114 “
292113 “
292112 “
291152 “

Total 59

1 Mile from proposed Miller 1-15 site

386599 Section 15 Harley J Bratcher
377136 Section 15 Casey G Donoho
358960 Section 15 William Brush
292821 Section 15 James Walston
292610 Section 15 Rod McGehee
292441 Section 15 Greg Clark
414694 Section 14 Roger Smith
396725 Section 14 Brent Bainbridge
396060 Section 14 Nick Lasnick
384721 Section 14 Eugene A Rhinehart
378123 Section 14 Seventh Day Adventist Church
359565 Section 14 Bill Jennings
358930 Section 14 Dairy West Inc
357254 Section 14 Roger Smith
352561 Section 14 Earl W Colson
349248 Section 14 Mike England
294049 Section 14 Denton Hovde
294041 Section 14 Bill Jennings
289852 Section 14 Earl W Colson
401087 Section 14 Prescott E Wilkie
393256 Section 14 Barry Zimmerman
388695 Section 14 Stanly Russel
385260 Section 14 Rob Fitch
371300 Section 14 Stanly Russel
371297 Section 14 Stanly Russel
371257 Section 14 Lawrence Sharp
371256 Section 14 Whiting Real Estate
358947 Section 14 Frank Franek
291121 Section 14 Dennis Yates
291113 Section 14 Dennis Yates
291112 Section 14 Dennis Yates

Total 31

1.5 miles:

443876 Section 15 Dave Burt
393783 Section 15 Dane Sarson
358986 Section 15 Pat Anouye
348947 Section 15 Bill Mordhorst
294152 Section 23 Donald W Wilson
294076 Section 23 Jim E Green
293410 Section 23 Mel Person

293118 Section 23 Charlie Pslieger
291 831 Section 23 Kevin Brett Natress
291613 Section 23 Danny Cox
404368 Section 23 City of Fruitland
358675 Section 23 Kemish Hendershot
393938 Section 23 Riley J Hill
371226 Section 23 Mesa Park Subdivision
293360 Section 23 EuLahala Webster
461096 Section23 Thomas Hood
408031 Section 23 Todd Barnes
371225 Section 23 Bud Kaesler
386649 Section 23 Stephen J Perkins
371228 Section 22 Russel Sharritt
293498 Section 22 Warren Carnifix
444608 Section 22 Diane Gibson
386650 Section 23 Lonnie Charles Davis
357087 Section 23 Church of Jesus Christ of the Latter Day Saints
421722 Section 23 Rodney Rhinehart
425300 Section 22 Lewis Brockus
404866 Section 22 Swire Coca Cola USA
404865 "
404864 "
292374 Section 22 City of Fruitland
454337 Section 22 Connie Limbaugh
390640 Section 15 Riverside Trailer Court
385380 Section 15 Tom Grossen

Total 33

Businesses located 1 mile or less from Miller 1-15 drill site

Medical (39)

Saint Alphonsus Health Plaza
St. Luke's Urgent Care
St. Luke's E.R.
MSTI-Mountain States Tumor Institute
St. Luke's Breast Detection Center
Respite House at St. Luke's Cancer Institute
Canyon Home Care & Hospice
First Choice Home Health & Hospice
Horizon Home Health & Hospice
Heart 'n Home Hospice
Snake River Pediatrics
Foot & Ankle Medical Center
DaVita Kidney Care
Idaho Skin & Surgery Center
Idaho Oral Surgery
Snake River Dermatology
Iwasa Eye Center
Buhrley Endodontics & Microsurgery
Idaho Kid's Dentistry
Children's Dentistry of Fruitland
Timmon's Dental
Assisting Hands Home Care
RISE Services, Inc.
GM Chiropractic
Precision Chiropractic
Total Wellness Chiropractic
Fruitland Chiropractic
Snake River Veterinary Center
Current Physical Therapy
Sol Physiotherapy
Tri-City Physical Therapy
Metis Mentoring
IV-Licious Therapy
Prescription Pad Pharmacy
St. Luke's Pharmacy
Hearing Life of Fruitland
Hearing Connection
Wienhoff Drug Testing
Total Health Inc.

Residential Subdivisions (9)

O'Dell Subdivisions
Rivercrest Subdivision
Northview Rance Subdivision
Syringa Springs Subdivision

Grace-Independent & Assistive Living
Edgewood Spring Creek-Assistive Living
Desert Rose Estates Mobile Home Park
Neat Retreat RV Park
River Ridge Estates Senior Mobile Home Park

Preschools & Daycare Facilities (5)

Little Digits Child Care
West Valley Preschool
R&R Art Center & PreK
Learn & Grow Little Red Roost Child Care
Little Scholars Learning Center & Nursery

Places of Worship (4)

Calvary Church
Church of Jesus Christ Latter- Day Saints
West Valley Free Methodist Church
Corpus Christi Catholic Church

Sports & Recreation (3)

Mesa Park
Payette County Recreation Department
RDP Releve Dance Project

Food Providers (14)

Dickinson Frozen Food
Jack Henry Coffee Shop
Mrs Ohh's Cookie
Idaho Pizza
Black Cow Eats & Drinks
Ogawa's Wicked Sushi, Burgers & Bowls
Jack in the Box
Ali's Mexican Restaurant
Domino's Pizza
Panzeri's Pizza
Rustic Pig BBQ
Soda Shop
We Dream Ice Cream
Bordertown Coffee & Bakeshop

Banking & Insurance (12)

Idaho Central Credit Union
Zion Bank
First Interstate Bank
Key Bank
DL Evans

State Farm Insurance
Holt Insurance
American Insurance
Farm Bureau Insurance
FIG Financial Insurance Group
Silver Key Insurance
BIG Insurance Company

Real Estate (9)

Pioneer Title Company
First Colony Mortgage
Amerititle
Goldwing's Real Estate Group
Silver Creek Realty
Premier Group Realty West
Sweet Group Realty
Tri-Cities Real Estate
Homes of Idaho

Financial (11)

World Finance Loan & Tax Service
Half Price Title Loan
Lend Nation
Money Tree
Security Finance
Edward Jones
Accounting Northwest, PA
Millington & Co. CPA
Guerrant Co. CPA
Lamm & Co. CPA
Liberty Tax

Staffing (3)

Express Employment Professional
American Staffing

Fitness & Image (15)

Tease Color & Hair Studio
Rebel Hair Company
Mari's Beauty Salon
Platinum Hair Studios
Untamed Salon
Nu Image
ReVive! Salon Spa
Luxury Nail Shop
Magnolia Skin Studio

My Time Massage
The Body Fitness Centers
Tami's Clean Sweep
Four Rivers Crossfit
Grizzco Fitness
Pick & Pack Groceries

Miscellaneous (42)

Asplundh Tree Experts, LLC
Ellips Powered
Disaster Response
Intermountain Law
Superior Industrial Refrigeration
O'Dell Construction
Sky Storage
Woodgrain Millwork
Payette County Storage
Biz Zone
4-B's Storage & Stuff
Swire Coca-Cola, USA
Mini-Storage
Franklin Building Supply
Fruitland Storage
Smoke City
Tobacco Connection
Stateline Shed Sales & More
Gem State Pawn Shop
Conley's Mini-Barns
Jeannie's Cowgirl Bling Store
Every Day Dealz Outlet Store
PC Pals
TV Plumbing & Drain Service
Shell Gas & Convenience Store
Maverick Adventure's First Stop
Stinker Stores Gas Station
The Body Factory
Jiffy Lube
PAR Repair
Expert Auto Repair
Auto Zone
Mechanical Repairs & Welding
Ramirez Auto Detail
American APEX & Auto Repair
Miller's Auto Service & Repair
Speed-O-Motive
Tom's Motorcycle ATV Snowmobile Repair
Carstown US
Steve's Hometown Chevrolet & GMC
Stateline Auto Ranch Subaru
Wash Rack Car Wash

Sources: “health threat radius” for oil and gas operations

Scientific studies from university researchers, NIEHS-funded researchers, and environmental health assessments frequently identify a "health threat radius" for oil and gas drilling, **commonly focusing on distances ranging from 0.5 miles to over 1 mile (800 meters to 1.6+ kilometers)**. This zone is defined by increased risks of adverse birth outcomes, respiratory issues, cancer, and elevated exposure to toxic air pollutants like benzene. National Institute of Environmental H... +4

Key Findings on Health Threat Radii:

- **1.0–1.6 Mile Radius (Approx. 1 Mile):** A 2025/2026 Boston University study found that nearly 47 million Americans live within roughly a mile (1.6 km) of fossil fuel infrastructure (wells, pipelines, refineries), which is associated with higher risks of adverse birth outcomes and asthma. Another study indicated that children living within 1 mile of unconventional gas wells have 5-7 times higher risk of developing lymphoma.
- **0.5 Mile Radius (2,640 Feet):** The "Oil & Gas Threat Map" uses a 0.5-mile radius to identify communities at risk of exposure to volatile organic compounds (VOCs) and hazardous air pollutants (HAPs). Research supports this as a minimum setback, as studies have shown elevated health risks, such as birth defects and respiratory issues, within 0.5 miles to 1 mile.
- **Urban/Los Angeles Context:** Studies conducted by the University of Southern California (USC) in Los Angeles—often working in neighborhoods with high-density drilling—have found lower lung function and higher blood pressure in residents living within **1 kilometer (~0.62 miles)** of active drilling sites.
- **Childhood Cancer Risks:** Studies have linked childhood leukemia to living near unconventional oil and gas wells, with increased risk found for children living within **13 kilometers (~8 miles)**, but with the highest risk for those living within **5 kilometers (3.1 miles)** of such sites. Nature +8

Scientific Evidence Behind the Radius:

- **Birth Defects & Outcomes:** Studies have identified higher rates of birth defects (like neural tube defects) for mothers residing within 1 km or up to 7.5 km from unconventional gas development.
- **Air Pollutants:** Research has documented that air pollutants (benzene, formaldehyde, particulate matter) from oil and gas sites can exceed EPA-acceptable risk levels at distances of a mile or more from the source.
- **Setback Recommendations:** Public health experts have argued that existing legal setbacks (often 500–1,000 feet) are insufficient, with many advocating for a minimum of 1 mile to protect public health and vulnerable populations. FracTracker Alliance +3

While some studies identify 0.5 miles as a direct "threat radius," the consensus among research cited by organizations like the NIEHS is that hazards are highest within the immediate vicinity (≤0.5–1 mile) but can extend further depending on the density of the wells and environmental factors. National Institute of Environmental H... +1

STATE OF IDAHO
DEPARTMENT OF
ENVIRONMENTAL QUALITY

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www.deq.idaho.gov

Governor Brad Little
Director John H. Tippets

February 5, 2020

Richard Brown, Managing Member
Snake River Oil and Gas, LLC
P.O. Box 500
Magnolia, AR 71753

RE: Facility ID No. 075-00022, Project No. 62372, Snake River Oil and Gas, LLC – Little Willow Road Gathering Facility, New Plymouth
Transfer of Ownership by Permit to Construct Revision

Dear Mr. Brown:

The Department of Environmental Quality (DEQ) is issuing Permit to Construct (PTC) No. P-2015.0015, Project 62372 to Snake River Oil and Gas, LLC – Little Willow Road Gathering Facility, located in New Plymouth for a transfer of ownership. This PTC is issued in accordance with IDAPA 58.01.01.209.04 of the Rules for the Control of Air Pollution in Idaho and is based on the certified information received on January 29, 2020. The transfer of ownership is based on the following information:

Previous Permittee Information

Permittee:	Alta Mesa Services, LP – Little Willow Road Gathering Facility
Mailing Address:	15021 Katy Freeway, Suite 400, Houston, TX 77094
Facility Location:	4649 Little Willow Road, New Plymouth, ID 83655
Facility Contact:	Kaitlyn Mathews, Petroleum Engineer
Phone Number:	(281) 943-1339
E-mail Address:	kmathews@altamesa.net
Responsible Official:	Dale Hayes, VP of Operations
Phone Number:	(281) 530-0991

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Updated Permittee Information

Permittee:	Snake River Oil and Gas, LLC – Little Willow Road Gathering Facility
Mailing Address:	117 E Calhoun Street (Box 500), Magnolia, AR 71753
Facility Location:	4649 Little Willow Road, New Plymouth, ID 83655
Facility Contact:	Nathan Caldwell, Operations Manager
Phone Number:	(870) 234-3050
E-mail Address:	caldwell.nathan@weiser-brown.com
Responsible Official:	Richard Brown, Managing Member
Phone Number:	(870) 234-3050

This permit is effective immediately and replaces PTC No. P-2015.0015, Project 61636, issued February 22, 2016. This permit does not release Snake River Oil and Gas, LLC – Little Willow Road Gathering Facility from compliance with all other applicable federal, state, or local laws, regulations, permits, or ordinances.

In order to fully understand the compliance requirements of this permit, DEQ highly recommends that you schedule a meeting with Dave Luft, Air Quality Manager, at (208) 373-0201 to review and discuss the terms and conditions of this permit. Should you choose to schedule this meeting, DEQ recommends that the following representatives attend the meeting: your facility's plant manager, responsible official, environmental contact, and any other staff responsible for day-to-day compliance with permit conditions.

If you have any questions, please contact Kelli Wetzel at (208) 373-0575 or kelli.wetzel@deq.idaho.gov.

Sincerely,

Dave Pangburn

per, Mike Simon
Stationary Source Program Manager
Air Quality Division

Attachment

MS/kw Permit No. P-2015.0015 PROJ 62372

Air Quality

PERMIT TO CONSTRUCT

Permittee	Snake River Oil and Gas, LLC – Little Willow Road Gathering Facility
Permit Number	P-2015.0015
Project ID	62372
Facility ID	075-00022
Facility Location	4649 Little Willow Rd New Plymouth, ID 83655

Permit Authority

This permit (a) is issued according to the "Rules for the Control of Air Pollution in Idaho" (Rules), IDAPA 58.01.01.200–228; (b) pertains only to emissions of air contaminants regulated by the State of Idaho and to the sources specifically allowed to be constructed or modified by this permit; (c) has been granted on the basis of design information presented with the application; (d) does not affect the title of the premises upon which the equipment is to be located; (e) does not release the permittee from any liability for any loss due to damage to person or property caused by, resulting from, or arising out of the design, installation, maintenance, or operation of the proposed equipment; (f) does not release the permittee from compliance with other applicable federal, state, tribal, or local laws, regulations, or ordinances; and (g) in no manner implies or suggests that the Idaho Department of Environmental Quality (DEQ) or its officers, agents, or employees assume any liability, directly or indirectly, for any loss due to damage to person or property caused by, resulting from, or arising out of design, installation, maintenance, or operation of the proposed equipment. Changes in design, equipment, or operations may be considered a modification subject to DEQ review in accordance with IDAPA 58.01.01.200–228.

Date Issued February 5, 2020

Kelli Wetzel

Kelli Wetzel, Permit Writer

Dan Pangburn

for **Mike Simon, Stationary Source Manager**

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1 Permit Scope

Purpose

1.1 This is a change of ownership permit transfer to Snake River Oil and Gas, LLC – Little Willow Road Gathering Facility from Alta Mesa Services, LP – Little Willow Road Gathering Facility.

1.2 This PTC replaces Permit to Construct No. P-2015.0015, issued on February 22, 2016.

Regulated Sources

Table 1.1 lists all sources of regulated emissions in this permit.

Table 1.1 Regulated Sources

Permit Section	Source	Control Equipment
2	Reboiler Rated capacity: 0.25 MMBtu/hr Allowable fuel type: natural gas only	None
2	Vapor Combustor Rated capacity: 2.5 MMBtu/hr Allowable fuel type: natural gas only	
2	10 Line Heaters Rated capacity: From 0.5 to 1.0 MMBtu/hr each Allowable fuel type: natural gas only	None
2	Dehydrator Throughput: 20 MMscf/day	Control Efficiency 98%
2	6 Oil Tanks Capacity: 1000 bbl each	Controlled by the Vapor Combustor Control Efficiency 98.0%
2	6 Water Tanks Capacity: 500 bbl each	
2	Oil Loading	Control Efficiency 98.0%
2	2 Heater Treaters Rated capacity: 1.0 and 2.5 MMBtu/hr Allowable fuel type: natural gas only	None
3	Compressor Engine 1 Max Capacity: 690 bhp Allowable fuel type: natural gas only	None

[February 22, 2016]

2 Natural Gas Gathering Facility

2.1 Process Description

The facility gathers natural gas from individual well sites where produced gas, oil, and water is separated and prepared for pipeline delivery to the refrigeration plant.

Production from individual well sites flow into individual line heaters/separators (gas production units). Separated water is piped to tanks and trucked off site. Crude is also piped to tanks and trucked off site. Flashed vapors from the tanks are collected in a venting system and piped to a vapor combustor to be burned. Condensate from all of the individual gas production units comingle and flow into a single three-phase separator to allow flashed gas from pressure reduction to separate out before metering. The condensate is metered and proceeds to a 4" pipeline for transport to the refrigeration plant approximately 11 miles to the south. The separated gas from the individual gas production units is compressed in an engine compressor to pipeline pressure. From there, the gas flows into an electric cooler to be cooled and then into a 98% emission free dehydrator. The gas is then metered and proceeds to a 12" pipeline for transport to the refrigeration plant.

2.2 Control Device Descriptions

Table 2.1 Natural Gas and Hydrocarbon Treatment Facility Description

Emissions Units / Processes	Control Devices
Reboiler	None
10 Line Heaters	None
Dehydrator	None
6 Water Tanks	None
6 Oil Storage Tanks	Vapor Combustor
2 Heater Treaters	None
Oil Loading	None

[February 22, 2016]

Emission Limits

2.3 Emission Limit

The permittee shall not discharge to the atmosphere from any fuel burning equipment with a maximum rated input of ten million BTU per hour or more, PM in excess of 0.015 gr/dscf corrected to 3% oxygen, in accordance with IDAPA 58.01.01.676-677.

2.4 Opacity Limit

Emissions from the any stack, vent, or functionally equivalent opening shall not exceed 20% opacity for a period or periods aggregating more than three minutes in any 60-minute period as required by IDAPA 58.01.01.625. Opacity shall be determined by the procedures contained in IDAPA 58.01.01.625.

Operating Requirements

2.5 Fuel Type Restriction

All fuel burning equipment listed in Table 2.1 shall be fired on natural gas exclusively.

2.6 Vapor Combustor

The facility shall be equipped with a vapor combustor designed to collect the total organic compound vapors displaced from tank trucks during product loading and from the oil tanks.

2.7 Reasonable Control of Fugitive Emissions

All reasonable precautions shall be taken to prevent particulate matter (PM) from becoming airborne in accordance with IDAPA 58.01.01.650-651. In determining what is reasonable, considerations will be given to factors such as the proximity of dust-emitting operations to human habitations and/or activities and atmospheric conditions that might affect the movement of PM. Some of the reasonable precautions include, but are not limited to, the following:

- Use, where practical, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads, or the clearing of lands.
- Application, where practical, of asphalt, oil, water, or suitable chemicals to, or covering of, dirt roads, material stockpiles, and other surfaces which can create dust.
- Installation and use, where practical, of hoods, fans, and fabric filters or equivalent systems to enclose and vent the handling of dusty materials. Adequate containment methods should be employed during sandblasting or other operations.
- Covering, where practical, of open-bodied trucks transporting materials likely to give rise to airborne dusts. Paving of roadways and their maintenance in a clean condition, where practical.
- Prompt removal of earth or other stored material from streets, where practical.

Monitoring and Recordkeeping Requirements

2.8 Opacity Monitoring

The permittee shall conduct a quarterly facility-wide inspection of potential sources of visible emissions, during daylight hours and under normal operating conditions. The inspection shall consist of a see/no see evaluation for each potential source of visible emissions. If any visible emissions are present from any point of emission, the permittee shall either

a) take appropriate corrective action as expeditiously as practicable to eliminate the visible emissions. Within 24 hours of the initial see/no see evaluation and after the corrective action, the permittee shall conduct a see/no see evaluation of the emissions point in question. If the visible emissions are not eliminated, the permittee shall comply with b).

or

b) perform a Method 9 opacity test in accordance with the procedures outlined in IDAPA 58.01.01.625. A minimum of 30 observations shall be recorded when conducting the opacity test. If opacity is greater than 20%, as measured using Method 9, for a period or periods aggregating more than three minutes in any 60-minute period, the permittee shall take all necessary corrective action and report the exceedance in accordance with IDAPA 58.01.01.130-136.

The permittee shall maintain records of the results of each visible emission inspection and each opacity test when conducted. The records shall include, at a minimum, the date and results of each inspection and test and a description of the following: the permittee's assessment of the conditions existing at the time visible emissions are present (if observed), any corrective action taken in response to the visible emissions, and the date corrective action was taken.

2.9 Responsible Control Measures

The permittee shall conduct a quarterly facility-wide inspection of potential sources of fugitive emissions, during daylight hours and under normal operating conditions, to ensure that the methods used to reasonably control fugitive emissions are effective. If fugitive emissions are not being reasonably controlled, the permittee shall take corrective action as expeditiously as practicable. The permittee shall maintain records of the results of each fugitive emissions inspection. The records shall include, at a minimum, the date of each inspection and a description of the following: the permittee's assessment of the conditions existing at the time fugitive emissions were present (if observed), any corrective action taken in response to the fugitive emissions, and the date the corrective action was taken. A compilation of the most recent five years of records shall be kept onsite and made available to DEQ representatives upon request.

Federal Requirements

40 CFR 60 Subpart OOOO Requirements

"Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution"

2.10 In accordance with 40 CFR 60.5370, the permittee must be in compliance with the standards of this subpart no later than October 15, 2012 or upon startup, whichever is later.

2.11 In accordance with 40 CFR 60.5400(a), the permittee must comply with the requirements of §§60.482-1a(a), (b), and (d), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401 for the group of all equipment, except compressors, within a process unit.

2.12 In accordance with 40 CFR 60.482-1a(a), the permittee must demonstrate compliance with the requirements of §§60.482-1a through 60.482-10a or §60.480a(e) for all equipment within 180 days of initial startup.

2.13 In accordance with 40 CFR 60.482-1a(b), compliance will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485a.

2.14 In accordance with 40 CFR 60.482-1a(d), equipment that is in vacuum service is excluded from the requirements of §§60.482-2a through 60.482-10a if it is identified as required in §60.486a(e)(5).

2.15 In accordance with 40 CFR 60.482-2a(a)(1), each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in §60.485a(b), except as provided in §60.482-1a(c) and (f) and paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in §60.482-1a(c) and paragraphs (d), (e), and (f) of this section.

2.16 In accordance with 40 CFR 60.482-2a(a)(2), each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in §60.482-1a(f).

2.17 In accordance with 40 CFR 60.482-2a(b)(1), the instrument reading that defines a leak is specified below:

- 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;
- 2,000 ppm or greater for all other pumps.

2.18 In accordance with 40 CFR 60.482-2a(b)(2), if there are indications of liquids dripping from the pump seal, the permittee shall follow the procedure below. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified, whichever is applicable.

- Monitor the pump within 5 days as specified in §60.485a(b). A leak is detected if the instrument reading measured during monitoring indicates a leak. The leak shall be repaired using the procedures in paragraph (c) of this section.
- Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

2.19 In accordance with 40 CFR 60.482-2a(c)(1), when a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9a.

2.20 In accordance with 40 CFR 60.482-2a(c)(2), a first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described below, where practicable.

- Tightening the packing gland nuts;
- Ensuring that the seal flush is operating at design pressure and temperature.

2.21 In accordance with 40 CFR 60.482-2a(d), each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified below are met.

- Each dual mechanical seal system is:
    - Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or
    - Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482-10a; or
    - Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.
- The barrier fluid system is in heavy liquid service or is not in VOC service.
- Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.
- Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.
    - If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.
        - Monitor the pump within 5 days as specified in §60.485a(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.
        - Designate the visual indications of liquids dripping as a leak.

- Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.
    - The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.
    - If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.
- When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.
    - A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.
    - A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

2.22 In accordance with 40 CFR 60.482-2a(e), any pump that is designated, as described in §60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

- Has no externally actuated shaft penetrating the pump housing;
- Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in §60.485a(c); and
- Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

2.23 In accordance with 40 CFR 60.482-2a(f), if any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of §60.482-10a, it is exempt from paragraphs (a) through (e) of this section.

2.24 In accordance with 40 CFR 60.482-2a(g), any pump that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

- The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and
- The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

2.25 In accordance with 40 CFR 60.482-2a(h), any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

2.26 In accordance with 40 CFR 60.482-4a(a), except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in §60.485a(c).

2.27 In accordance with 40 CFR 60.482-4a(b), after each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in §60.482-9a.

- No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in §60.485a(c).

2.28 In accordance with 40 CFR 60.482-4a(c), any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in §60.482-10a is exempted from the requirements of paragraphs (a) and (b) of this section.

2.29 In accordance with 40 CFR 60.482-4a(d), any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements below.

- After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in §60.482-9a.

2.30 In accordance with 40 CFR 60.482-5a(a), each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in §60.482-1a(c) and paragraph (c) of this section.

2.31 In accordance with 40 CFR 60.482-5a(b), each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified below.

- Gases displaced during filling of the sample container are not required to be collected or captured.
- Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.
- Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.
- Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either paragraph below.
    - Return the purged process fluid directly to the process line.
    - Collect and recycle the purged process fluid to a process.
    - Capture and transport all the purged process fluid to a control device that complies with the requirements of §60.482-10a.
    - Collect, store, and transport the purged process fluid to any of the following systems or facilities:

- A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;
- A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266;
- A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261;
- A waste management unit subject to and operated in compliance with the treatment requirements of 40 CFR 61.348(a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of 40 CFR 61.343 through 40 CFR 61.347; or
- A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR part 279, subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR part 261.

2.32 In accordance with 40 CFR 60.482-5a(c), in-situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

2.33 In accordance with 40 CFR 60.482-6a(a), each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in §60.482-1a(c) and paragraphs (d) and (e) of this section.

- The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

2.34 In accordance with 40 CFR 60.482-6a(b), each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

2.35 In accordance with 40 CFR 60.482-6a(c), when a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

2.36 In accordance with 40 CFR 60.482-6a(d), open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a), (b), and (c) of this section.

2.37 In accordance with 40 CFR 60.482-6a(e), open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

2.38 In accordance with 40 CFR 60.482-7a(a), each valve shall be monitored monthly to detect leaks by the methods specified in §60.485a(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g),and (h) of this section, §60.482-1a(c) and (f), and §§60.483-1a and 60.483-2a.

- A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section, §60.482-1a(c), and §§60.483-1a and 60.483-2a.
    - Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.
    - If the existing valves in the process unit are monitored in accordance with §60.483-1a or §60.483-2a, count the new valve as leaking when calculating the percentage of valves leaking as described in §60.483-2a(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

2.39 In accordance with 40 CFR 60.482-7a(b), if an instrument reading of 500 ppm or greater is measured, a leak is detected.

2.40 In accordance with 40 CFR 60.482-7a(c), any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

- As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.
- If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

2.41 In accordance with 40 CFR 60.482-7a(d), when a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in §60.482-9a.

- A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

2.42 In accordance with 40 CFR 60.482-7a(e), first attempts at repair include, but are not limited to, the following best practices where practicable:

- Tightening of bonnet bolts;
- Replacement of bonnet bolts;
- Tightening of packing gland nuts;
- Injection of lubricant into lubricated packing.

2.43 In accordance with 40 CFR 60.482-7a(f), any valve that is designated, as described in §60.486a(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

- Has no external actuating mechanism in contact with the process fluid,
- Is operated with emissions less than 500 ppm above background as determined by the method specified in §60.485a(c), and

- Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

2.44 In accordance with 40 CFR 60.482-7a(g), any valve that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

- The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and
- The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

2.45 In accordance with 40 CFR 60.482-7a(h), any valve that is designated, as described in §60.486a(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

- The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.
- The process unit within which the valve is located either:
    - Becomes an affected facility through §60.14 or §60.15 and was constructed on or before January 5, 1981; or
    - Has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.
- The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

2.46 In accordance with 40 CFR 60.482-8a(a), if evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

- The owner or operator shall monitor the equipment within 5 days by the method specified in §60.485a(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.
- The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

2.47 In accordance with 40 CFR 60.482-8a(b), if an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

2.48 In accordance with 40 CFR 60.482-8a(c), when a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9a.

- The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

2.49 In accordance with 40 CFR 60.482-8a(d), first attempts at repair include, but are not limited to, the best practices described under §§60.482-2a(c)(2) and 60.482-7a(e).

2.50 In accordance with 40 CFR 60.482-9a(a), delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

2.51 In accordance with 40 CFR 60.482-9a(b), delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

2.52 In accordance with 40 CFR 60.482-9a(c), delay of repair for valves and connectors will be allowed if:

- The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and
- When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482-10a.

2.53 In accordance with 40 CFR 60.482-9a(d), delay of repair for pumps will be allowed if:

- Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and
- Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

2.54 In accordance with 40 CFR 60.482-9a(e), delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

2.55 In accordance with 40 CFR 60.482-9a(f), when delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

2.56 In accordance with 40 CFR 60.482-10a(a), owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

2.57 In accordance with 40 CFR 60.482-10a(b), vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent.

2.58 In accordance with 40 CFR 60.482-10a(c), enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

2.59 In accordance with 40 CFR 60.482-10a(f), except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (2) of this section.

- If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements below:
    - Conduct an initial inspection according to the procedures in §60.485a(b); and
    - Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

- If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:
    - Conduct an initial inspection according to the procedures in §60.485a(b); and
    - Conduct annual inspections according to the procedures in §60.485a(b).

2.60 In accordance with 40 CFR 60.482-10a(g), leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

- A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.
- Repair shall be completed no later than 15 calendar days after the leak is detected.

2.61 In accordance with 40 CFR 60.482-10a(h), delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

2.62 In accordance with 40 CFR 60.482-10a(i), if a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

2.63 In accordance with 40 CFR 60.482-10a(j), any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

- The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and
- The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

2.64 In accordance with 40 CFR 60.482-10a(k), any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified below:

- The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and
- The process unit within which the closed vent system is located becomes an affected facility through §§60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and
- The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

2.65 In accordance with 40 CFR 60.482-10a(l), the permittee shall record the information specified in below.

- Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.
- Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.
- For each inspection during which a leak is detected, a record of the information specified in §60.486a(c).
- For each inspection conducted in accordance with §60.485a(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.
- For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

2.66 In accordance with 40 CFR 60.482-10a(m), closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

2.67 In accordance with 40 CFR 60.482-11a(a), the permittee shall initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

2.68 In accordance with 40 CFR 60.482-11a(b), except as allowed in §60.482-1a(c), §60.482-10a, or as specified in paragraph (e) of this section, the permittee shall monitor all connectors in gas and vapor and light liquid service as specified below.

- The connectors shall be monitored to detect leaks by the method specified in §60.485a(b) and, as applicable, §60.485a(c).
- If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.
- The permittee shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.
    - If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).

- If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.
- If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.
    - The permittee shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.
    - If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.
    - If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

- If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.
- The permittee shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

2.69 In accordance with 40 CFR 60.482-11a(c), for use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$\%C_L = C_L / C_t * 100$

Where:

$\%C_L$ = Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

C_L = Number of connectors measured at 500 ppm or greater, by the method specified in §60.485a(b).

C_t = Total number of monitored connectors in the process unit or affected facility.

2.70 In accordance with 40 CFR 60.482-11a(d), when a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9a. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.

2.71 In accordance with 40 CFR 60.482-11a(e), any connector that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

- The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and
- The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

2.72 In accordance with 40 CFR 60.482-11a(f), inaccessible, ceramic, or ceramic-lined connectors. (1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of §§63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

- Buried;
- Insulated in a manner that prevents access to the connector by a monitor probe;
- Obstructed by equipment or piping that prevents access to the connector by a monitor probe;
- Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;
- Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or
- Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.
- If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

2.73 In accordance with 40 CFR 60.482-11a(g), except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

2.74 In accordance with 40 CFR 60.5400(b), the permittee may elect to comply with the requirements of §§60.483-1a and 60.483-2a, as an alternative.

2.75 In accordance with 40 CFR 60.483-1a(a), the permittee may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

2.76 In accordance with 40 CFR 60.483-1a(b), the following requirements shall be met if the permittee wishes to comply with an allowable percentage of valves leaking:

- An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in §60.487a(d).
- A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.
- If a valve leak is detected, it shall be repaired in accordance with §60.482-7a(d) and (e).

2.77 In accordance with 40 CFR 60.483-1a(c), performance tests shall be conducted in the following manner:

- All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in §60.485a(b).
- If an instrument reading of 500 ppm or greater is measured, a leak is detected.
- The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

2.78 In accordance with 40 CFR 60.483-1a(d), owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in §60.485a(h).

2.79 In accordance with 40 CFR 60.483-2a(a), the permittee may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

- An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in §60.487(d)a.

2.80 In accordance with 40 CFR 60.483-2a(b), the permittee shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in §60.482-7a.

- After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.
- After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.
- If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in §60.482-7a but can again elect to use this section.
- The percent of valves leaking shall be determined as described in §60.485a(h).
- The permittee must keep a record of the percent of valves found leaking during each leak detection period.

- A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with §60.482-7a(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

2.81 In accordance with 40 CFR 60.5400(c), the permittee may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of §60.5402 of this subpart.

2.82 In accordance with 40 CFR 60.5400(d), the permittee must comply with the provisions of §60.485a of this part except as provided in paragraph (f) of this section.

2.83 In accordance with 40 CFR 60.485(a)(a), in conducting the performance tests required in §60.8, the permittee shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

2.84 In accordance with 40 CFR 60.485(a)(b), the permittee shall determine compliance with the standards in §§60.482-1a through 60.482-11a, 60.483a, and 60.484a as follows:

- Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 of this part. The following calibration gases shall be used:
    - Zero air (less than 10 ppm of hydrocarbon in air); and
    - A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.
- A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except donot adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in §60.486a(e)(7). Calculate the average algebraic difference between the three meter readings and the most recent calibration value. Divide this algebraic difference by the initial calibration value and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

2.85 In accordance with 40 CFR 60.485(a)(c), the permittee shall determine compliance with the no-detectable-emission standards in §§60.482-2a(e), 60.482-3a(i), 60.482-4a, 60.482-7a(f), and 60.482-10a(e) as follows:

- The requirements of paragraph (b) shall apply.
- Method 21 of appendix A-7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

2.86 In accordance with 40 CFR 60.485(a)(d), the permittee shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

- Procedures that conform to the general methods in ASTM E260-73, 91, or 96, E168-67, 77, or 92, E169-63, 77, or 93 (incorporated by reference—see §60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.
- Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.
- Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

2.87 In accordance with 40 CFR 60.485(a)(e), the permittee shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

- The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference—see §60.17) shall be used to determine the vapor pressures.
- The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight.
- The fluid is a liquid at operating conditions.

2.88 In accordance with 40 CFR 60.485(a)(f), samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

2.89 In accordance with 40 CFR 60.485(a)(h), the permittee shall determine compliance with §60.483-1a or §60.483-2a as follows:

- The percent of valves leaking shall be determined using the following equation:

  $\%V_L = (V_L / V_T) * 100$

  Where:

  $\%V_L$ = Percent leaking valves.

  V_L = Number of valves found leaking.

  V_T = The sum of the total number of valves monitored.

- The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.
- The number of valves leaking shall include valves for which repair has been delayed.
- Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.
- If the process unit has been subdivided in accordance with §60.482-7a(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.
- The total number of valves monitored does not include a valve monitored to verify repair.

2.90 In accordance with 40 CFR 60.5400(e), the permittee must comply with the provisions of §§60.486a and 60.487a of this part except as provided in §§60.5401, 60.5421, and 60.5422 of this part.

2.91 In accordance with 40 CFR 60.486(a)(a), each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

- An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.
- The permittee shall record the information specified in paragraphs (a)(3)(i) through (v) of this section for each monitoring event required by §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a.
    - Monitoring instrument identification.
    - Operator identification.
    - Equipment identification.
    - Date of monitoring.
    - Instrument reading.

2.92 In accordance with 40 CFR 60.486(a)(b), when each leak is detected as specified in §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following requirements apply:

- A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.
- The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §60.482-7a(c) and no leak has been detected during those 2 months.
- The identification on a connector may be removed after it has been monitored as specified in §60.482-11a(b)(3)(iv) and no leak has been detected during that monitoring.
- The identification on equipment, except on a valve or connector, may be removed after it has been repaired.

2.93 In accordance with 40 CFR 60.486(a)(c), when each leak is detected as specified in §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

- The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.
- The date the leak was detected and the dates of each attempt to repair the leak.
- Repair methods applied in each attempt to repair the leak.

- Maximum instrument reading measured by Method 21 of appendix A-7 of this part at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.
- "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.
- The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.
- The expected date of successful repair of the leak if a leak is not repaired within 15 days.
- Dates of process unit shutdowns that occur while the equipment is unrepaired.
- The date of successful repair of the leak.

2.94 In accordance with 40 CFR 60.486(a)(d), the following information pertaining to the design requirements for closed vent systems and control devices described in §60.482-10a shall be recorded and kept in a readily accessible location:

- Detailed schematics, design specifications, and piping and instrumentation diagrams.
- The dates and descriptions of any changes in the design specifications.
- A description of the parameter or parameters monitored, as required in §60.482-10a(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.
- Periods when the closed vent systems and control devices required in §§60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a are not operated as designed, including periods when a flare pilot light does not have a flame.
- Dates of startups and shutdowns of the closed vent systems and control devices required in §§60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a.

2.95 In accordance with 40 CFR 60.486(a)(e), the following information pertaining to all equipment subject to the requirements in §§60.482-1a to 60.482-11a shall be recorded in a log that is kept in a readily accessible location:

- A list of identification numbers for equipment subject to the requirements of this subpart.
- A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§60.482-2a(e), 60.482-3a(i), and 60.482-7a(f).
    - The designation of equipment as subject to the requirements of §60.482-2a(e), §60.482-3a(i), or §60.482-7a(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.
- A list of equipment identification numbers for pressure relief devices required to comply with §60.482-4a.
- The dates of each compliance test as required in §§60.482-2a(e), 60.482-3a(i), 60.482-4a, and 60.482-7a(f).
    - The background level measured during each compliance test.
    - The maximum instrument reading measured at the equipment during each compliance test.
- A list of identification numbers for equipment in vacuum service.

- A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with §60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.
- The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.
- Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A-7 of this part and §60.485a(b).
    - Date of calibration and initials of operator performing the calibration.
    - Calibration gas cylinder identification, certification date, and certified concentration.
    - Instrument scale(s) used.
    - A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A-7 of this part.
    - Results of each calibration drift assessment required by §60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).
    - If an owner or operator makes their own calibration gas, a description of the procedure used.
- The connector monitoring schedule for each process unit as specified in §60.482-11a(b)(3)(v).
- Records of each release from a pressure relief device subject to §60.482-4a.

2.96 In accordance with 40 CFR 60.486(a)(f), the following information pertaining to all valves subject to the requirements of §60.482-7a(g) and (h), all pumps subject to the requirements of §60.482-2a(g), and all connectors subject to the requirements of §60.482-11a(e) shall be recorded in a log that is kept in a readily accessible location:

- A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.
- A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

2.97 In accordance with 40 CFR 60.486(a)(g), the following information shall be recorded for valves complying with §60.483-2a:

- A schedule of monitoring.
- The percent of valves found leaking during each monitoring period.

2.98 In accordance with 40 CFR 60.486(a)(h), the following information shall be recorded in a log that is kept in a readily accessible location:

- Design criterion required in §§60.482-2a(d)(5) and 60.482-3a(e)(2) and explanation of the design criterion; and
- Any changes to this criterion and the reasons for the changes.

2.99 In accordance with 40 CFR 60.486(a)(i), the following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in §60.480a(d):

- An analysis demonstrating the design capacity of the affected facility,
- A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and
- An analysis demonstrating that equipment is not in VOC service.

2.100 In accordance with 40 CFR 60.486(a)(j), information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

2.101 In accordance with 40 CFR 60.486(a)(k), the provisions of §60.7(b) and (d) do not apply to affected facilities subject to this subpart.

2.102 In accordance with 40 CFR 60.487(a)(a), each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.

2.103 In accordance with 40 CFR 60.487(a)(b), the initial semiannual report to the Administrator shall include the following information:

- Process unit identification.
- Number of valves subject to the requirements of §60.482-7a, excluding those valves designated for no detectable emissions under the provisions of §60.482-7a(f).
- Number of pumps subject to the requirements of §60.482-2a, excluding those pumps designated for no detectable emissions under the provisions of §60.482-2a(e) and those pumps complying with §60.482-2a(f).
- Number of compressors subject to the requirements of §60.482-3a, excluding those compressors designated for no detectable emissions under the provisions of §60.482-3a(i) and those compressors complying with §60.482-3a(h).
- Number of connectors subject to the requirements of §60.482-11a.

2.104 In accordance with 40 CFR 60.487(a)(c), all semiannual reports to the Administrator shall include the following information, summarized from the information in §60.486a:

- Process unit identification.
- For each month during the semiannual reporting period,
    - Number of valves for which leaks were detected as described in §60.482-7a(b) or §60.483-2a,
    - Number of valves for which leaks were not repaired as required in §60.482-7a(d)(1),
    - Number of pumps for which leaks were detected as described in §60.482-2a(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),
    - Number of compressors for which leaks were detected as described in §60.482-3a(f),
    - Number of compressors for which leaks were not repaired as required in §60.482-3a(g)(1),
    - Number of connectors for which leaks were detected as described in §60.482-11a(b),

- Number of connectors for which leaks were not repaired as required in §60.482-11a(d), and
- The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

- Dates of process unit shutdowns which occurred within the semiannual reporting period.
- Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

2.105 In accordance with 40 CFR 60.487(a)(d), the permittee electing to comply with the provisions of §§60.483-1a or 60.483-2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

2.106 In accordance with 40 CFR 60.487(a)(e), the permittee shall report the results of all performance tests in accordance with §60.8 of the General Provisions. The provisions of §60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

2.107 In accordance with 40 CFR 60.487(a)(f), the requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the state.

2.108 In accordance with 40 CFR 60.5400(f), the permittee must use the following provision instead of §60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in §60.17) must be used.

2.109 In accordance with 40 CFR 60.5401(a), the permittee may comply with the following exceptions to the provisions of §60.5400(a) and (b).

2.110 In accordance with 40 CFR 60.5401(b), each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b) except as provided in §60.5400(c) and in paragraph (b)(4) of this section, and §60.482-4a(a) through (c) of subpart VVa.

- If an instrument reading of 500 ppm or greater is measured, a leak is detected.
- When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.
  - A first attempt at repair must be made no later than 5 calendar days after each leak is detected.
- Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1) of subpart VVa.

- No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

2.111 In accordance with 40 CFR 60.5401(c), sampling connection systems are exempt from the requirements of §60.482-5a.

2.112 In accordance with 40 CFR 60.5401(d), pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§60.482-2a(a)(1) and 60.482-7a(a), and paragraph (b)(1) of this section.

2.113 In accordance with 40 CFR 60.5401(f), the permittee may use the following provisions instead of §60.485a(e):

- Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).
- Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302 °F) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

2.114 In accordance with 40 CFR 60.5401(g), the permittee may use the following provisions instead of §60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in §60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

2.115 In accordance with 40 CFR 60.5402(a), if, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

2.116 In accordance with 40 CFR 60.5402(b), any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

2.117 In accordance with 40 CFR 60.5402(c), the Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

2.118 In accordance with 40 CFR 60.5402(d), the Administrator will treat applications under this section according to the following criteria, except in cases where the Administrator concludes that other criteria are appropriate:

- The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.
- If the applicant is an owner or operator of an affected facility, the applicant must commit in writing to operate and maintain the alternative means so as to achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard.

2.119 In accordance with 40 CFR 60.5410, the permittee must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (i) of this section. The initial compliance period begins on October 15, 2012, or upon initial startup, whichever is later, and ends no later than one year after the initial startup date for the permittee's affected facility or no later than one year after October 15, 2012. The initial compliance period may be less than one full year.

2.120 In accordance with 40 CFR 60.5410(a), to achieve initial compliance with the standards for each well completion operation conducted at the gas well affected facility the permittee must comply with paragraphs below.

- The permittee must submit the notification required in §60.5420(a)(2).
- The permittee must submit the initial annual report for the well affected facility as required in §60.5420(b).
- The permittee must maintain a log of records as specified in §60.5420(c)(1)(i) through (iv) for each well completion operation conducted during the initial compliance period.
- For each gas well affected facility subject to both §60.5375(a)(1) and (3), as an alternative to retaining the records specified in §60.5420(c)(1)(i) through (iv), the permittee may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each gas well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

2.121 In accordance with 40 CFR 60.5410(d), to achieve initial compliance with emission standards for the permittee's pneumatic controller affected facility the permittee must comply with the requirements specified below.

- The permittee must demonstrate initial compliance by maintaining records as specified in §60.5420(c)(4)(ii) of the permittee's determination that the use of a pneumatic controller affected facility with a bleed rate greater than 6 standard cubic feet of gas per hour is required as specified in §60.5390(a).
- The permittee own or operate a pneumatic controller affected facility located at a natural gas processing plant and the permittee's pneumatic controller is driven by a gas other than natural gas and therefore emits zero natural gas.

- The permittee own or operate a pneumatic controller affected facility located between the wellhead and a natural gas processing plant and the manufacturer's design specifications indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.
- The permittee must tag each new pneumatic controller affected facility according to the requirements of §60.5390(b)(2) or (c)(2).
- The permittee must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for the permittee's pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of §60.5420(b).
- The permittee must maintain the records as specified in §60.5420(c)(4) for each pneumatic controller affected facility.

2.122 In accordance with 40 CFR 60.5410(f), for affected facilities at onshore natural gas processing plants, initial compliance with the VOC requirements is demonstrated if the permittee is in compliance with the requirements of §60.5400.

2.123 In accordance with 40 CFR 60.5415(a), for each gas well affected facility, the permittee must demonstrate continuous compliance by submitting the reports required by §60.5420(b) and maintaining the records for each completion operation specified in §60.5420(c)(1).

2.124 In accordance with 40 CFR 60.5415(d), for each pneumatic controller affected facility, the permittee must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

- The permittee must continuously operate the pneumatic controllers as required in §60.5390(a), (b), or (c).
- The permittee must submit the annual report as required in §60.5420(b).
- The permittee must maintain records as required in §60.5420(c)(4).

2.125 In accordance with 40 CFR 60.5415(f), for affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if the permittee is in compliance with the requirements of §60.5400.

2.126 In accordance with 40 CFR 60.5415(h), affirmative defense for violations of emission standards during malfunction. In response to an action to enforce the standards set forth in §§60.5375, 60.5380, 60.5385, 60.5390, 60.5395, 60.5400, and 60.5405, the permittee may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at §60.2. Appropriate penalties may be assessed, however, if the permittee fails to meet the burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

- To establish the affirmative defense in any action to enforce such a standard, the permittee must timely meet the reporting requirements in §60.5415(h)(2), and must prove by a preponderance of evidence that:
    - The violation:
        - Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

- Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and
- Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and
- Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

- Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and
- The frequency, amount and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and
- If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
- All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment and human health; and
- All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and
- All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and
- At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and
- A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

- Report. The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (h)(1) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

2.127 In accordance with 40 CFR 60.5420(a), the permittee must submit the notifications according to paragraphs (a)(1) and (2) of this section if the permittee owns or operates one or more of the affected facilities specified in §60.5365 that was constructed, modified, or reconstructed during the reporting period.

- If the permittee owns or operates a gas well, pneumatic controller, centrifugal compressor, reciprocating compressor or storage vessel affected facility the permittee is not required to submit the notifications required in §60.7(a)(1), (3), and (4).

- If the permittee owns or operates a gas well affected facility, the permittee must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the API well number, the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. The permittee may submit the notification in writing or in electronic format.
    - If the permittee is subject to state regulations that require advance notification of well completions and the permittee has met those notification requirements, then the permittee is considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

2.128 In accordance with 40 CFR 60.5420(b), the permittee must submit annual reports containing the information specified below to the Administrator and performance test reports as specified below. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to §60.5410. Subsequent annual reports are due no later than same date each year as the initial annual report. If the permittee owns or operates more than one affected facility, the permittee may submit one report for multiple affected facilities provided the report contains all of the information required as specified below. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. The permittee may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

- The general information specified below.
    - The company name and address of the affected facility.
    - An identification of each affected facility being included in the annual report.
    - Beginning and ending dates of the reporting period.
    - 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.
- For each gas well affected facility, the information below.
    - Records of each well completion operation as specified in paragraph (c)(1)(i) through (iv) of this section for each gas well affected facility conducted during the reporting period. In lieu of submitting the records specified in paragraph (c)(1)(i) through (iv), the owner or operator may submit a list of the well completions with hydraulic fracturing completed during the reporting period and the records required by paragraph (c)(1)(v) of this section for each well completion.
    - Records of deviations specified in paragraph (c)(1)(ii) of this section that occurred during the reporting period.
- For each pneumatic controller affected facility, the information specified below.
    - An identification of each pneumatic controller constructed, modified or reconstructed during the reporting period, including the identification information specified in §60.5390(b)(2) or (c)(2).

- If applicable, documentation that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.
- Records of deviations specified in paragraph (c)(4)(v) of this section that occurred during the reporting period.

- Within 60 days after the date of completing each performance test (see §60.8 of this part) as required by this subpart, except testing conducted by the manufacturer as specified in §60.5413(d), the permittee must submit the results of the performance tests required by this subpart to the EPA as follows. The permittee must use the latest version of the EPA's Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/index.html) existing at the time of the performance test to generate a submission package file, which documents the performance test. The permittee must then submit the file generated by the ERT through the EPA's Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed by logging in to the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/). Only data collected using test methods supported by the ERT as listed on the ERT Web site are subject to this requirement for submitting reports electronically. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, the permittee must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test to the Administrator at the appropriate address listed in §60.4.
- For enclosed combustors tested by the manufacturer in accordance with §60.5413(d), an electronic copy of the performance test results required by §60.5413(d) shall be submitted via email to Oil_and_Gas_PT@EPA.GOV unless the test results for that model of combustion control device are posted at the following Web site: epa.gov/airquality/oilandgas/.

2.129 In accordance with 40 CFR 60.5420(c), the permittee must maintain the records identified as specified in §60.7(f) and as identified below. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years.

- The records for each gas well affected facility as specified below.
  - Records identifying each well completion operation for each gas well affected facility;
  - Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in §60.5375.
  - Records required in §60.5375(b) or (f) for each well completion operation conducted for each gas well affected facility that occurred during the reporting period. The permittee must maintain the records specified in paragraphs below.

- For each gas well affected facility required to comply with the requirements of §60.5375(a), the permittee must record: The location of the well; the API well number; the duration of flowback; duration of recovery to the flow line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours of time.
- For each gas well affected facility required to comply with the requirements of §60.5375(f), the permittee must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that the permittee does not have to record the duration of recovery to the flow line.

- For each gas well facility for which the permittee claims an exception under §60.5375(a)(3), the permittee must record: The location of the well; the API well number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.
- For each gas well affected facility required to comply with both §60.5375(a)(1) and (3), if the permittee is using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, the permittee must retain the records of the digital photograph as specified in §60.5410(a)(4).

- For each pneumatic controller affected facility, the permittee must maintain the records identified below.
  - Records of the date, location and manufacturer specifications for each pneumatic controller constructed, modified or reconstructed.
  - Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.
  - If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.
  - If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.
  - Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in §60.5390.

2.130 In accordance with 40 CFR 60.5421(b), the following recordkeeping requirements apply to pressure relief devices subject to the requirements of §60.5401(b)(1) of this subpart.

- When each leak is detected as specified in §60.5401(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.
- When each leak is detected as specified in §60.5401(b)(2), the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:

- The instrument and operator identification numbers and the equipment identification number.
- The date the leak was detected and the dates of each attempt to repair the leak.
- Repair methods applied in each attempt to repair the leak.
- "Above 500 ppm" if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.
- "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.
- The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.
- The expected date of successful repair of the leak if a leak is not repaired within 15 days.
- Dates of process unit shutdowns that occur while the equipment is unrepaired.
- The date of successful repair of the leak.
- A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) must be signed by the owner or operator.

2.131 In accordance with 40 CFR 60.5422(b), the permittee must include the following information in the initial semiannual report in addition to the information required in §60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of §60.5401(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c).

2.132 In accordance with 40 CFR 60.5422(c), the permittee must include the following information in all semiannual reports in addition to the information required in §60.487a(c)(2)(i) through (vi):

- Number of pressure relief devices for which leaks were detected as required in §60.5401(b)(2); and
- Number of pressure relief devices for which leaks were not repaired as required in §60.5401(b)(3).

2.133 NSPS 40 CFR 60 – General Provisions

The permittee shall comply with the requirements of 40 CFR 60, Subpart A – General Provisions. A summary of applicable requirements for affected facilities is provided in the following table:

Table 2.2 Subpart A – General Provisions

Citation	Subject	Explanation
40 CFR 60.1	General Applicability of the General Provisions	
40 CFR 60.2	Definitions	Additional terms defined in §60.5430.
40 CFR 60.3	Units and abbreviations	
40 CFR 60.4	Address	
40 CFR 60.5	Determination of construction or modification	
40 CFR 60.6	Review of Plans	
40 CFR 60.7	Notification and record keeping	Except that §60.7 only applies as specified in §60.5420(a).
40 CFR 60.8	Performance tests	Performance testing is required for control devices used on storage vessels and centrifugal compressors.
40 CFR 60.9	Availability of information	
40 CFR 60.10	State authority	
40 CFR 60.12	Circumvention	
40 CFR 60.13	Monitoring requirements	Continuous monitors are required for storage vessels.
40 CFR 60.14	Modification	
40 CFR 60.15	Reconstruction	
40 CFR 60.16	Priority list	
40 CFR 60.17	Incorporations by reference	
40 CFR 60.18	General control device requirements	Except that §60.18 does not apply to flares.
40 CFR 60.19	General notification and reporting requirement	

2.134 Unless expressly provided otherwise, any reference in this permit to any document identified in IDAPA 58.01.01.107.03 shall constitute the full incorporation into this permit of that document for the purposes of the reference, including any notes and appendices therein. Documents include, but are not limited to:

- Standards of Performance for New Stationary Sources (NSPS), 40 CFR Part 60, Subpart OOOO and JJJJ.
- National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT), 40 CFR Part 63, Subpart ZZZZ

For permit conditions referencing or cited in accordance with any document incorporated by reference (including permit conditions identified as NSPS or NESHAP), should there be any conflict between the requirements of the permit condition and the requirements of the document, the requirements of the document shall govern, including any amendments to that regulation.

3 Compressor Engine 1

3.1 Process Description

Natural gas is compressed at the facility prior to transport to the refrigeration plant. The compressors will be driven by a 690 bhp Caterpillar natural gas-fired IC engine. The engine manufacture date has not been determined and is subject to 40 CFR 63, Subpart ZZZZ and/or 40 CFR 60 Subpart JJJJ if the engines are manufactured after June 12, 2006.

[February 22, 2016]

3.2 Control Device Descriptions

Table 3.1 Compressor Engines Description

Emissions Units / Processes	Control Devices
Compressor Engine 1	None

Emission Limits

3.3 Opacity Limit

Emissions from the Compressor Engine stack, or any other stack, vent, or functionally equivalent opening associated with the compressor engines, shall not exceed 20% opacity for a period or periods aggregating more than three minutes in any 60-minute period as required by IDAPA 58.01.01.625. Opacity shall be determined by the procedures contained in IDAPA 58.01.01.625.

Operating Requirements

3.4 Fuel Type Restriction

Compressor Engine 1 shall be fired on natural gas exclusively.

Monitoring and Recordkeeping Requirements

3.5 Opacity Monitoring

The permittee shall conduct a quarterly facility-wide inspection of potential sources of visible emissions, during daylight hours and under normal operating conditions. The inspection shall consist of a see/no see evaluation for each potential source of visible emissions. If any visible emissions are present from any point of emission, the permittee shall either

c) take appropriate corrective action as expeditiously as practicable to eliminate the visible emissions. Within 24 hours of the initial see/no see evaluation and after the corrective action, the permittee shall conduct a see/no see evaluation of the emissions point in question. If the visible emissions are not eliminated, the permittee shall comply with b).

or

d) perform a Method 9 opacity test in accordance with the procedures outlined in IDAPA 58.01.01.625. A minimum of 30 observations shall be recorded when conducting the opacity test. If opacity is greater than 20%, as measured using Method 9, for a period or periods aggregating more than three minutes in any 60-minute period, the permittee shall take all necessary corrective action and report the exceedance in accordance with IDAPA 58.01.01.130-136.

The permittee shall maintain records of the results of each visible emission inspection and each opacity test when conducted. The records shall include, at a minimum, the date and results of each inspection and test and a description of the following: the permittee's assessment of the conditions existing at the time visible emissions are present (if observed), any corrective action taken in response to the visible emissions, and the date corrective action was taken.

Federal Requirements

40 CFR 63 Subpart ZZZZ Requirements

"National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines"

3.6 In accordance with 40 CFR 63.6595(a)(1), the permittee must comply with the applicable emission and operating limitations of the National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ by October 19, 2013 or upon installation.

3.7 In accordance with 40 CFR 63.6603, the permittee shall comply with the requirements in Table 2d to install NSCR (non-selective catalytic reduction) to reduce HAP emissions on Compressor Engine 1.

3.8 In accordance with 40 CFR 63.6605, the permittee shall, at all times, operate and maintain Compressor Engine 1, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the permittee to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

3.9 In accordance with 40 CFR 63.6612, the permittee shall conduct any initial performance test or other initial compliance demonstration according to Table 5 to this subpart within 180 days after the compliance date of October 19, 2013. In order to comply with the requirement to reduce CO and THC emissions, the permittee shall:

- Install NSCR
- Conduct an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more.
- Install a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or install equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

3.10 In accordance with 40 CFR 63.6625(h), the permittee shall minimize Compressor Engine 1's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes.

3.11 In accordance with 40 CFR 63.6630(e), the permittee shall meet the following requirements to demonstrate initial compliance:

- The compliance demonstration must consist of at least three test runs.
- Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.
- To demonstrate compliance with the CO concentration or CO percent reduction requirement, the permittee must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.
- To demonstrate compliance with the THC percent reduction requirement, the permittee must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.
- The permittee must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.
- To demonstrate compliance with the CO or THC percent reduction requirement, the permittee must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

3.12 In accordance with 40 CFR 63.6635(a), the permittee must monitor and collect data for the Compressor Engine.

3.13 In accordance with 40 CFR 63.6635(b), the permittee must monitor continuously at all times that Compressor Engine 1 is operating except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

3.14 In accordance with 40 CFR 63.6635(c), the permittee may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. The permittee must, however, use all the valid data collected during all other periods.

3.15 In accordance with 40 CFR 63.6640(c), the annual compliance demonstration required shall be conducted according to the following requirements:

- The compliance demonstration must consist of at least one test run.
- Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.
- To demonstrate compliance with the CO concentration or CO percent reduction requirement, the permittee must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.
- To demonstrate compliance with the THC percent reduction requirement, the permittee must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

- The permittee must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.
- To demonstrate compliance with the CO or THC percent reduction requirement, the permittee must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.
- If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the permittee demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

3.16 In accordance with 40 CFR 63.6645(a), the permittee shall submit all of the notifications in §§63.7(b) and (c) that apply by the dates specified for Compressor Engine 1.

3.17 In accordance with 40 CFR 63.6645(g), the permittee shall submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1) for Compressor Engine 1.

3.18 In accordance with 40 CFR 63.6645(h), the permittee shall submit a Notification of Compliance Status according to §63.9(h)(2)(ii) for Compressor Engine 1.

- The permittee shall submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

3.19 In accordance with 40 CFR 63.6650(b), the permittee shall, for semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for the affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for the source in §63.6595.

- The permittee shall ensure, for semiannual Compliance reports, that the first Compliance report be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date.
- The permittee shall ensure, for semiannual Compliance reports, each subsequent Compliance report cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.
- The permittee shall ensure, for semiannual Compliance reports, each subsequent Compliance report be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

3.20 In accordance with 40 CFR 63.6650(c), the permittee's Compliance report must contain the following:

- Company name and address.
- Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.
- Date of report and beginning and ending dates of the reporting period.

- If a malfunction occurred during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by the permittee during a malfunction to minimize emissions including actions taken to correct a malfunction.
- If there are no deviations from any emission or operating limitations that apply, a statement that there were no deviations from the emission or operating limitations during the reporting period.

3.21 In accordance with 40 CFR 63.6655(a), the permittee shall keep the following records:

- A copy of each notification and report that is submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that is submitted.
- Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.
- Records of performance tests and performance evaluations.
- Records of all required maintenance performed on the air pollution control and monitoring equipment.
- Records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

3.22 In accordance with 40 CFR 63.6655(d), the permittee shall keep the records required in Table 6 to this subpart to show compliance with each emission or operating limitation for Compressor Engine 1.

3.23 In accordance with 40 CFR 63.6655 (e), the permittee shall keep the records of the maintenance conducted on the stationary RICE, Compressor Engine 1, in order to demonstrate that the permittee operated and maintained the stationary RICE and after-treatment control device (if any) according to the permittee's own maintenance plan.

3.24 In accordance with 40 CFR 63.6660(a), the permittee shall keep the records in a form suitable and readily available for expeditious review according to 40 CFR 63.10(b)(1).

3.25 In accordance with 40 CFR 63.6660(b), the permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

3.26 In accordance with 40 CFR 63.6660(c), the permittee shall keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1).

3.27 NESHAPS 40 CFR 63 – General Provisions

The permittee shall comply with the requirements of 40 CFR 63, Subpart A – General Provisions. A summary of applicable requirements for affected facilities is provided in the following table:

Table 3.2 Subpart A – General Provisions

Citation	Subject	Explanation
40 CFR 63.1(a)(1)-(12)	General Applicability	
40 CFR 63.1(b)(1)-(3)	Initial Applicability Determination	Applicability of subpart ZZZZ is also specified in 40 CFR 63.6585
40 CFR 63.1(c)(1)	Applicability After Standard Established	
40 CFR 63.1(c)(2)	Applicability of Permit Program for Area Sources	
40 CFR 63.1(c)(5)	Notifications	
40 CFR 63.2	Definitions	Additional definitions are specified in 40 CFR 63.6675.
40 CFR 63.3(a)–(c)	Units and Abbreviations	
40 CFR 63.4(a)(1)–(5)	Prohibited Activities	
40 CFR 63.4(b)–(c)	Circumvention/Fragmentation	
40 CFR 63.6(a)	Compliance With Standards and Maintenance Requirements—Applicability	
40 CFR 63.6(b)(1)-(7)	Compliance Dates for New and Reconstructed Sources	40 CFR 63.6595 specifies the compliance dates.
40 CFR 63.6(c)(1)-(5)	Compliance Dates for Existing Sources	40 CFR 63.6595 specifies the compliance dates.
40 CFR 63.6(f)(2)-(3)	Methods for Determining Compliance	
40 CFR 63.6(g)(1)-(3)	Use of an Alternative Standard	
40 CFR 63.6(i)(1)-(16)	Extension of Compliance	
40 CFR 63.6(j)	Presidential Compliance Exemption	
40 CFR 63.7(a)(1)-(2)	Performance Test Dates	40 CFR 63.6610-6612 specify the performance test dates
40 CFR 63.7(b)(1)-(2)	Notification of Performance Test and Rescheduling	40 CFR 63.6645 specifies the notification
40 CFR 63.7(e)(2)	Conduct Performance Test and reduction of data	40 CFR 63.6620 specifies appropriate test methods
40 CFR 63.7(g)	Performance Test data analysis and recordkeeping and reporting	
40 CFR 63.8	Monitoring Requirements	40 CFR 63.6625 specifies appropriate monitoring requirements
40 CFR 63.9(a)-(e), (g)-(j)	Notification Requirements	40 CFR 63.645 specifies notification requirements.
40 CFR 63.10(a)	Recordkeeping/Reporting—Applicability and General Information	
40 CFR 63.10(b)(1)	General Recordkeeping Requirements	Additional requirements are specified in 40 CFR 63.6655
40 CFR 63.10(b)(2)(xii)	Waiver of recordkeeping requirements	
40 CFR 63.10(b)(2)(xiv)	Records supporting notifications	
40 CFR 63.10(b)(3)	Recordkeeping Requirements for Applicability Determinations	
40 CFR 63.10(d)(1)	General Reporting Requirements	Additional requirements are specified in 40 CFR 63.6650
40 CFR 63.10(d)(4)	Progress Reports for Sources With Compliance Extensions	
40 CFR 63.10(f)	Recordkeeping/Reporting Waiver	
40 CFR 63.12	State Authority and Delegations	
40 CFR 63.13	Addresses of State Air Pollution Control Agencies and EPA Regional Offices	
40 CFR 63.14	Incorporation by Reference	
40 CFR 63.15	Availability of Information/Confidentiality	

40 CFR 60 Subpart JJJJ Requirements
"Standards of Performance for Stationary Spark Ignition Internal Combustion Engines"

3.28 In accordance with 40 CFR 60.4233, the permittee must comply with the emission standards in Table 1 to this subpart for Compressor Engine 1.

Table 3.3 Table 1 to Subpart JJJJ of Part 60 – NO_x, CO and VOC Emission Standards for Stationary Non-Emergency SI Gas Engines ≥100 HP

Engine type and fuel	Maximum engine power	Manufacture date	Emission Standards [a]					
			g/hp-hr			ppmvd at 15% O_2		
			NO_X	CO	VOC [b]	NO_X	CO	VOC [b]
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG (except lean burn 500≤HP<1,350)	hp≥500	7/1/2007	2.0	4.0	1.0	160	540	86
	hp≥500	7/1/2010	1.0	2.0	0.7	82	270	60

a) Owners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/hp-hr or ppmvd at 15 percent O_2.

b) For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

3.29 In accordance with 40 CFR 60.4234, the permittee shall operate and maintain stationary SI ICE that achieve the emission standards as required in 40 CFR 60.4233(e) over the entire life of the engine.

3.30 In accordance with 40 CFR 60.4243(b)(1), if the permittee chooses to purchase a certified engine, the permittee shall purchase an engine certified according to procedures specified in the subpart for the same model year demonstrating compliance to one of the methods specified in paragraph (a) of the section.

3.31 In accordance with 40 CFR 60.4243(b)(2)(ii), if the permittee chooses to purchase a non-certified engine, the permittee shall keep a maintenance plan and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition the permittee must conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

3.32 In accordance with 40 CFR 60.4244(a), each performance test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and according to the requirements in §60.8 and under the specific conditions that are specified by Table 2 to this subpart.

Table 3.4 Table 2 to Subpart JJJJ of Part 60—Requirements for Performance Tests

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary SI internal combustion engine demonstrating compliance according to §60.4244.	a. limit the concentration of NO_x in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)[a].	(a) If using a control device, the sampling site must be located at the outlet of the control device.
	ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)[a].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_x concentration.	
	iii. Determine the exhaust flow rate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60.		
	iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for NO_x concentration.	
	v. Measure NO_x at the exhaust of the stationary internal combustion engine.	(5) Method 7E of 40 CFR part 60, appendix A, Method D6522–00(2005)[a], Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(d) Results of this test consist of the average of the three 1-hour or longer runs.	
	b. limit the concentration of CO in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A.	(a) If using a control device, the sampling site must be located at the outlet of the control device.
	ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)[a].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for CO concentration.	
	iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for CO concentration.	

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary SI internal combustion engine demonstrating compliance according to §60.4244.	v. Measure CO at the exhaust of the stationary internal combustion engine.	(5) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00(2005)[a], Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17).	(d) Results of this test consist of the average of the three 1-hour or longer runs.	
	c. limit the concentration of VOC in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A.	(a) If using a control device, the sampling site must be located at the outlet of the control device.
	ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)[a].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for VOC concentration.	
	iii. Determine the exhaust flow rate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60.		
	iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for VOC concentration.	
	v. Measure VOC at the exhaust of the stationary internal combustion engine.	(5) Methods 25A and 18 of 40 CFR part 60, appendix A, Method 25A with the use of a methane cutter as described in 40 CFR 1065.265, Method 18 or 40 CFR part 60, appendix A,[c,d] Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(d) Results of this test consist of the average of the three 1-hour or longer runs.	

a) ASTM D6522–00 is incorporated by reference; see 40 CFR 60.17. Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

b) You may use ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses, for measuring the O_2 content of the exhaust gas as an alternative to EPA Method 3B.

c) You may use EPA Method 18 of 40 CFR part 60, appendix A, provided that you conduct an adequate presurvey test prior to the emissions test, such as the one described in OTM 11 on EPA's Web site (http://www.epa.gov/ttn/emc/prelim/otm11.pdf).

d) You may use ASTM D6420–99 (2004), Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry as an alternative to EPA Method 18 for measuring total nonmethane organic.

3.33 In accordance with 40 CFR 60.4244(b), the permittee may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c). If the stationary SI internal combustion engine is non-operational, the permittee does not need to startup the engine solely to conduct a performance test; however, the permittee must conduct the performance test immediately upon startup of the engine.

3.34 In accordance with 40 CFR 60.4244(c), the permittee must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.

3.35 In accordance with 40 CFR 60.4244(d), to determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 1:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{HP - hr} \quad \text{(Eq. 1)}$$

Where:

ER = Emission rate of NOX in g/HP-hr.

Cd = Measured NOX concentration in parts per million by volume (ppmv).

1.912×10−3 = Conversion constant for ppm NOX to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, horsepower-hour (HP-hr).

3.36 In accordance with 40 CFR 60.4244(e), to determine compliance with the CO mass per unit output emission limitation, convert the concentration of CO in the engine exhaust using Equation 2:

$$ER = \frac{C_d \times 1.164 \times 10^{-3} \times Q \times T}{HP - hr} \quad \text{(Eq. 2)}$$

Where:

ER = Emission rate of CO in g/HP-hr.

Cd = Measured CO concentration in ppmv.

1.164×10−3 = Conversion constant for ppm CO to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

3.37 In accordance with 40 CFR 60.4244(f), when calculating emissions of VOC, emissions of formaldehyde should not be included. To determine compliance with the VOC mass per unit output emission limitation, convert the concentration of VOC in the engine exhaust using Equation 3:

$$ER = \frac{C_d \times 1.833 \times 10^{-3} \times Q \times T}{HP - hr} \quad \text{(Eq. 3)}$$

Where:

ER = Emission rate of VOC in g/HP-hr.

Cd = VOC concentration measured as propane in ppmv.

1.833×10−3 = Conversion constant for ppm VOC measured as propane, to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

3.38 In accordance with 40 CFR 60.4244(g), if the permittee chooses to measure VOC emissions using either Method 18 of 40 CFR part 60, appendix A, or Method 320 of 40 CFR part 63, appendix A, then it has the option of correcting the measured VOC emissions to account for the potential differences in measured values between these methods and Method 25A. The results from Method 18 and Method 320 can be corrected for response factor differences using Equations 4 and 5 of this section. The corrected VOC concentration can then be placed on a propane basis using Equation 6 of this section.

$$RF_i = \frac{C_{Mi}}{C_{Ai}} \qquad \text{(Eq. 4)}$$

Where:

RFi = Response factor of compound i when measured with EPA Method 25A.

CMi = Measured concentration of compound i in ppmv as carbon.

CAi = True concentration of compound i in ppmv as carbon.

$$C_{icorr} = RF_i \times C_{imeas} \qquad \text{(Eq. 5)}$$

Where:

Cicorr = Concentration of compound i corrected to the value that would have been measured by EPA Method 25A, ppmv as carbon.

Cimeas = Concentration of compound i measured by EPA Method 320, ppmv as carbon.

$$C_{Peq} = 0.6098 \times C_{icorr} \qquad \text{(Eq. 6)}$$

Where:

CPeq = Concentration of compound i in mg of propane equivalent per DSCM.

3.39 In accordance with 40 CFR 60.4245(a)(1) and (2), the permittee shall keep records of the following information:

- For each engine notifications submitted and all documentation supporting any notification.
- Maintenance conducted on each SI engine.
- If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to §60.4243(a)(2), documentation that the engine meets the emission standards.

The permittee shall maintain these records on-site and be made available to DEQ representatives upon request for a period of at least five years.

3.40 In accordance with 40 CFR 60.4245(c), owners and operators of stationary SI ICE greater than or equal to 500 HP that have not been certified by an engine manufacturer to meet the emission standards in §60.4231 must submit an initial notification as required in §60.7(a)(1). The notification must include the following information.

- Name and address of the owner or operator;
- The address of the affected source;
- Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;
- Emission control equipment; and
- Fuel used.

3.41 In accordance with 40 CFR 60.4245(d), the permittee shall submit a copy of each performance test as conducted in §60.4244 within 60 days after the test has been completed.

3.42 In accordance with 40 CFR 60.4246, the permittee shall comply with the following applicable General Provisions of 40 CFR 60:

Table 3.5 Table 3 to Subpart JJJJ of Part 60—Applicability of General Provisions to Subpart JJJJ

General Provision Citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4248.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4245.
§60.8	Performance tests	Yes	Except that §60.8 only applies to owners and operators who are subject to performance testing in subpart JJJJ.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	Yes	Requirements are specified in subpart JJJJ.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	No	
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

4 General Provisions

General Compliance

4.1 The permittee has a continuing duty to comply with all terms and conditions of this permit. All emissions authorized herein shall be consistent with the terms and conditions of this permit and the "Rules for the Control of Air Pollution in Idaho." The emissions of any pollutant in excess of the limitations specified herein, or noncompliance with any other condition or limitation contained in this permit, shall constitute a violation of this permit, the "Rules for the Control of Air Pollution in Idaho," and the Environmental Protection and Health Act (Idaho Code §39-101, et seq.)

[Idaho Code §39-101, et seq.]

4.2 The permittee shall at all times (except as provided in the "Rules for the Control of Air Pollution in Idaho") maintain in good working order and operate as efficiently as practicable all treatment or control facilities or systems installed or used to achieve compliance with the terms and conditions of this permit and other applicable Idaho laws for the control of air pollution.

[IDAPA 58.01.01.211, 5/1/94]

4.3 Nothing in this permit is intended to relieve or exempt the permittee from the responsibility to comply with all applicable local, state, or federal statutes, rules, and regulations.

[IDAPA 58.01.01.212.01, 5/1/94]

Inspection and Entry

4.4 Upon presentation of credentials, the permittee shall allow DEQ or an authorized representative of DEQ to do the following:

- Enter upon the permittee's premises where an emissions source is located, emissions-related activity is conducted, or where records are kept under conditions of this permit;
- Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;
- Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
- As authorized by the Idaho Environmental Protection and Health Act, sample or monitor, at reasonable times, substances or parameters for the purpose of determining or ensuring compliance with this permit or applicable requirements.

[Idaho Code §39-108]

Construction and Operation Notification

4.5 This permit shall expire if construction has not begun within two years of its issue date, or if construction is suspended for one year.

[IDAPA 58.01.01.211.02, 5/1/94]

4.6 The permittee shall furnish DEQ written notifications as follows:

- A notification of the date of initiation of construction, within five working days after occurrence; except in the case where pre-permit construction approval has been granted then notification shall be made within five working days after occurrence or within five working days after permit issuance whichever is later;
- A notification of the date of any suspension of construction, if such suspension lasts for one year or more;

- A notification of the anticipated date of initial start-up of the stationary source or facility not more than sixty days or less than thirty days prior to such date; and
- A notification of the actual date of initial start-up of the stationary source or facility within fifteen days after such date; and
- A notification of the initial date of achieving the maximum production rate, within five working days after occurrence - production rate and date.

[IDAPA 58.01.01.211.03, 5/1/94]

Performance Testing

4.7 If performance testing (air emissions source test) is required by this permit, the permittee shall provide notice of intent to test to DEQ at least 15 days prior to the scheduled test date or shorter time period as approved by DEQ. DEQ may, at its option, have an observer present at any emissions tests conducted on a source. DEQ requests that such testing not be performed on weekends or state holidays.

4.8 All performance testing shall be conducted in accordance with the procedures in IDAPA 58.01.01.157. Without prior DEQ approval, any alternative testing is conducted solely at the permittee's risk. If the permittee fails to obtain prior written approval by DEQ for any testing deviations, DEQ may determine that the testing does not satisfy the testing requirements. Therefore, at least 30 days prior to conducting any performance test, the permittee is encouraged to submit a performance test protocol to DEQ for approval. The written protocol shall include a description of the test method(s) to be used, an explanation of any or unusual circumstances regarding the proposed test, and the proposed test schedule for conducting and reporting the test.

4.9 Within 30 days, or up to 60 days when requested following the date in which a performance test required by this permit is concluded, the permittee shall submit to DEQ a performance test report. The written report shall include a description of the process, identification of the test method(s) used, equipment used, all process operating data collected during the test period, and test results, as well as raw test data and associated documentation, including any approved test protocol.

[IDAPA 58.01.01.157, 4/5/00]

Monitoring and Recordkeeping

4.10 The permittee shall maintain sufficient records to ensure compliance with all of the terms and conditions of this permit. Monitoring records shall include, but not be limited to, the following: (a) the date, place, and times of sampling or measurements; (b) the date analyses were performed; (c) the company or entity that performed the analyses; (d) the analytical techniques or methods used; (e) the results of such analyses; and (f) the operating conditions existing at the time of sampling or measurement. All monitoring records and support information shall be retained for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Supporting information includes, but is not limited to, all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. All records required to be maintained by this permit shall be made available in either hard copy or electronic format to DEQ representatives upon request.

[IDAPA 58.01.01.211, 5/1/94]

Excess Emissions

4.11 The permittee shall comply with the procedures and requirements of IDAPA 58.01.01.130–136 for excess emissions due to start-up, shut-down, scheduled maintenance, safety measures, upsets, and breakdowns.

[IDAPA 58.01.01.130–136, 4/5/00]

Certification

4.12 All documents submitted to DEQ—including, but not limited to, records, monitoring data, supporting information, requests for confidential treatment, testing reports, or compliance certification—shall contain a certification by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete.

[IDAPA 58.01.01.123, 5/1/94]

False Statements

4.13 No person shall knowingly make any false statement, representation, or certification in any form, notice, or report required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.125, 3/23/98]

Tampering

4.14 No person shall knowingly render inaccurate any monitoring device or method required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.126, 3/23/98]

Transferability

4.15 This permit is transferable in accordance with procedures listed in IDAPA 58.01.01.209.06.

[IDAPA 58.01.01.209.06, 4/11/06]

Severability

4.16 The provisions of this permit are severable, and if any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

[IDAPA 58.01.01.211, 5/1/94]

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue, Suite 155
Seattle, WA 98101-3188

JAN - 7 2020

ENFORCEMENT & COMPLIANCE ASSURANCE DIVISION

Reply To: 20 – C04

CERTIFIED MAIL — RETURN RECEIPT REQUESTED

Mr. Scott Ricks
President
Alta Mesa Services, LP;
Northwest Gas Processing, LLC; and
High Mesa Services, LLC
15021 Katy Freeway, Suite 400
Houston, Texas 77094

Re: Notice and Finding of Violation
Alta Mesa Services, LP; Northwest Gas Processing, LLC; and High Mesa Services, LLC
Houston, Texas

Dear Mr. Ricks:

The U.S. Environmental Protection Agency is issuing the enclosed Notice and Finding of Violation ("NOV/FOV") to Alta Mesa Services, LP, Northwest Gas Processing, LLC, and High Mesa Services, LLC (collectively "Alta Mesa" or "you") under Section 113(a)(1) and (3) of the Clean Air Act, 42 U.S.C. § 7413(a)(1) and (3). We find that you are violating certain permits issued under the Idaho State Implementation Plan ("SIP") and the Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution for which Construction, Modification, or Reconstruction Commenced After August 23, 2011 found in 40 C.F.R. Part 60, Subpart OOOO, as well as the Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced After September 18, 2015, Subpart OOOOa, at the Little Willow Road Gathering Station located at 4649 Little Willow Road, New Plymouth, Idaho, and the Northwest Gas Processing Facility located at 4303 Highway 30 South, New Plymouth, Idaho.

Section 113 of the Clean Air Act gives us several enforcement options. These options include issuing an administrative compliance order, issuing an administrative penalty order and bringing a judicial civil or criminal action.

We are offering you an opportunity to confer with us about the violations alleged in the NOV/FOV. The conference will give you an opportunity to present information on the specific findings of violation, any efforts you have taken to comply and the steps you will take to prevent future violations. In addition, in order to make the conference more productive, we encourage you to submit to us information responsive to the NOV/FOV prior to the conference date.

Please plan for your facility's technical and management personnel to attend the conference to discuss compliance measures and commitments. You may have an attorney represent you at this conference.

The EPA contact in this matter is Victoria Nelson. You may contact Ms. Nelson at (312) 886-9481 or by email at nelson.victoria@epa.gov, to request a conference. If you choose to have an attorney request a conference on Alta Mesa's behalf, your attorney may contact Robert Peachey in EPA's Office of Regional Counsel at (312) 353-4510 or by email at peachey.robert@epa.gov. You should make the request within 10 calendar days following receipt of this letter. We should hold any conference within 30 calendar days following receipt of this letter.

Sincerely,

Edward Kowalski
Director

Enclosure

cc: Steve Bacom
Idaho Department of Environmental Quality

Diane Kassab
Alta Mesa Services, LP

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10

IN THE MATTER OF:	)	
	)	
Alta Mesa Services, LP;	)	**NOTICE AND FINDING OF**
Northwest Gas Processing, LLC; and	)	**VIOLATION**
High Mesa Services, LLC	)	
Houston, Texas	)	
	)	
Proceedings Pursuant to	)	
Section 113(a)(1) and (3) of the	)	
Clean Air Act, 42 U.S.C.	)	
§ 7413(a)(1) and (3)	)	

NOTICE AND FINDING OF VIOLATION

The U.S. Environmental Protection Agency ("EPA") is issuing this Notice and Finding of Violation ("NOV/FOV") under Section 113(a)(1) and (3) of the Clean Air Act ("CAA"), 42 U.S.C. § 7413(a)(1) and (3). Based on available information and as explained below, EPA finds that Alta Mesa Services, LP, Northwest Gas Processing, LLC, and/or High Mesa Services, LLC (collectively "Alta Mesa") is violating certain permits issued under the Idaho State Implementation Plan ("SIP"), as well as Section 111(e) of the CAA, 42 U.S.C. § 7411(e), specifically the Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution for which Construction, Modification, or Reconstruction Commenced After August 23, 2011 found in 40 C.F.R. Part 60, Subpart OOOO ("Subpart OOOO"); and the Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced After September 18, 2015 found in 40 C.F.R. Part 60, Subpart OOOOa ("Subpart OOOOa"), as follows:

Statutory and Regulatory Authority

1. The CAA is designed to, among other things, protect and enhance the quality of the nation's air so as to promote the public health and welfare and the productive capacity of its population. *See* Section 101(b)(1) of the CAA, 42 U.S.C. § 7401(b)(1).

Recordkeeping, Inspections, Monitoring, and Entry

2. Section 114(a) of the CAA, 42 U.S.C. § 7414(a), authorizes the Administrator of EPA to require the submission of information for purposes of determining whether any person is in violation of any standard of performance developed under Section 111 of the CAA, 42 U.S.C. § 7411, or in violation of any requirement of a SIP developed pursuant to 42 U.S.C. § 7410. The Administrator has delegated this authority to the Regional Administrator, who has redelegated the authority to the Director of the Enforcement and Compliance Assurance Division, Region 10.

The Idaho SIP

3. Pursuant to Section 110(a)(1) of the CAA, 42 U.S.C. § 7410(a)(1), each state is responsible for adopting and submitting to EPA for approval an implementation plan that provides for the implementation, maintenance, and enforcement of National Ambient Air Quality Standards ("NAAQS") for particular pollutants, including ground-level ozone.

4. Under Section 110(a)(2) of the CAA, 42 U.S.C. § 7410(a)(2), each SIP must include enforceable emissions limitations and other control measures, means, or techniques, as well as schedule for compliance, as may be necessary to meet applicable requirements, and must include a permit program to provide for the enforcement of these limitations, measures, and schedule as necessary to assure the NAAQS are achieved. Upon EPA's approval of a SIP, the plans become independently enforceable by the federal government, as stated under Section 113(a)(1) of the CAA, 42 U.S.C. § 7413(a)(1).

5. EPA has approved various provisions of the Idaho Administrative Procedures Act ("IDAPA") as part of the Idaho SIP, including IDAPA § 58.01.01.200 through 222. *See* 40 C.F.R. § 52.670(c).

The New Source Performance Standards and NSPS Subpart OOOO

6. Section 111 of the CAA, 42 U.S.C. § 7411, requires EPA to implement a New Source Performance Standards ("NSPS") program for the control of air pollutant emissions. NSPS regulations impose nationally uniform emission standards for new or modified stationary sources falling within industrial categories that significantly contribute to air pollution.

7. In 2012, EPA promulgated NSPS regulations for the crude oil and natural gas production, transmission, and distribution industry sector, which were codified at Subpart OOOO. 77 Fed Reg. 49,542 (Aug. 16, 2012). EPA has reconsidered and revised certain provisions of Subpart OOOO. *See, e.g.,* 78 Fed Reg. 58,416 (Sept. 23, 2013); and 79 Fed Reg. 79,037 (Dec. 31, 2014).

8. Subpart OOOO establishes emission standards for the control of volatile organic compounds ("VOC") and sulfur dioxide emissions from various types of oil and natural gas production, processing, transmission, storage, and distribution equipment constructed, modified, or reconstructed after August 23, 2011, and on or before September 18, 2015, including storage vessels.

9. Subpart OOOO, at 40 C.F.R. § 60.5430, defines "storage vessel" as a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of non-earthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support.

10. Among other things, Subpart OOOO addresses two classes of storage vessels: (i) those that began to be constructed, reconstructed or modified after August 23, 2011, and on or before April 12, 2013 (called "Group 1 storage vessels"); and (ii) those that began to be constructed, reconstructed or modified after April 12, 2013, and on or before September 18, 2015 (called "Group 2 storage vessels"). 40 C.F.R. § 60.5430.

11. A Group 1 or Group 2 storage vessel is an affected facility subject to Subpart OOOO requirements if a properly performed emission determination indicates that the storage vessel has the potential for VOC emissions equal to or greater than six (6) tons per year. 40 C.F.R. § 60.5365(e). A storage vessel meeting these criteria is defined as a "storage vessel affected facility."

12. A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than six (6) tons per year shall remain an affected facility under Subpart OOOO. 40 C.F.R. § 60.5365(e)(2).

13. The potential for VOC emissions from a storage vessel must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in 40 C.F.R. § 60.5365. For Group 1 storage vessels, the applicable emission determination deadline was October 15, 2013. For Group 2 storage vessels, the applicable emission determination deadline was April 15, 2014, or 30 days after startup (whichever was later). 40 C.F.R. §§ 60.5365(e), 60.5410(h)(1).

14. In calculating the potential VOC emissions from a storage vessel, the determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, State, local or tribal authority. *See* 40 C.F.R. § 60.5365(e).

15. Subpart OOOO requires the owner/operator of a storage vessel affected facility to comply with certain emission control requirements:

a. The owner/operator of a storage vessel affected facility must either: (i) reduce VOC emissions from the storage vessel by 95.0 percent; or (ii) maintain the uncontrolled actual VOC emissions from the storage vessel at less than four (4) tons per year without considering control. *See* 40 C.F.R. § 60.5395(d)(1)-(2).

b. For a storage vessel subject to the 95.0 percent emission reduction requirement, the required emission reduction must be achieved by control requirements that include equipping the storage vessel with a cover that meets the requirements of 40 C.F.R. § 60.5411(b), connecting the storage vessel to a closed vent system that meets the requirements of 40 C.F.R. § 60.5411(c), and either: (i) routing the storage vessel vapors to a control device (such as an enclosed combustor) that meets certain requirements; or (ii) routing the storage vessel vapors to a process. 40 C.F.R. § 60.5395(e).

16. Subpart OOOO, at 40 C.F.R. § 60.5412(d), requires that each control device used to meet the emission reduction standard in 40 C.F.R. § 60.5395(d) for storage vessel affected facilities must be installed according to 40 C.F.R. § 60.5395(d)(1) through (3), as applicable. As an alternative to 40 C.F.R. § 60.5395(d)(1), owners/operators of storage vessel affected facilities may install a control device model tested under 40 C.F.R. § 60.5413(d), which meets the criteria in 40 C.F.R. § 60.5413(d)(11) and § 60.5413(e).

17. Subpart OOOO, at 40 C.F.R. § 60.5412(d)(1)(ii), requires that, for each enclosed combustion device, owners/operators must install and operate a continuous burning pilot flame.

18. Subpart OOOO, at 40 C.F.R. § 60.5413(e), requires that owners/operators of combustion control devices tested by the manufacturer demonstrate that the control device achieves the performance requirements in 40 C.F.R. § 60.5413(d)(11) by installing a device tested under 40 C.F.R. § 60.5413(d) and complying with the criteria specified in 40 C.F.R. § 60.5413(e)(1) through (7).

19. Subpart OOOO, at 40 C.F.R. § 60.5413(e)(2), requires that a pilot flame on the combustion control device must be present at all times of operation.

20. Subpart OOOO, at 40 C.F.R. § 60.5410(h), requires that owners/operators of storage vessel affected facilities comply with certain initial compliance demonstration requirements, as well as initial notification and annual reporting requirements:

a. The owner/operator of a storage vessel affected facility must make a formal determination of its initial compliance with the standards applicable to the storage vessel. *See* 40 C.F.R. § 60.5410.

b. For a Group 1 storage vessel, the owner/operator was required to demonstrate initial compliance by April 15, 2015. For a Group 2 storage vessel, the owner operator was required to demonstrate initial compliance by April 15, 2014, or within 60 days after startup, whichever was later. *See* 40 C.F.R. § 60.5410(h).

c. The owner/operator of a storage vessel affected facility must retain records documenting initial compliance with the standards applicable to the storage vessel. *See* 40 C.F.R. § 60.5410(h)(5).

d. The owner/operator of a storage vessel affected facility must submit annual reports containing specified information. *See* 40 C.F.R. § 60.5420. For a Group 1 storage vessel, an initial annual report was due by no later than January 15, 2014, with a notification identifying each Group 1 storage vessel. For a Group 2 storage vessel, an initial annual report was due by no later than July 14, 2014, or 120 days after startup (whichever was later). *See* 40 C.F.R. §§ 60.5395(b)(1), 60.5410, 60.5420(b); 78 Fed. Reg. 58,416 (Sept. 23, 2013).

e. Among other things, each annual report must include: (i) an identification of each storage vessel affected facility for which construction, modification, or reconstruction commenced during the reporting period; and (ii) a statement that initial compliance with the applicable VOC emission reduction and control requirements has been achieved for the relevant storage vessel(s). *See* 40 C.F.R. § 60.5420(b)(6)(i), (v).

21. Subpart OOOO requires the owner/operator of a storage vessel affected facility to comply with additional monitoring and recordkeeping requirements:

a. If vapors from a storage vessel affected facility are routed to a control device or a process, Subpart OOOO requires monthly olfactory, visual, and auditory inspections to identify defects in the storage vessel cover and closed vent system that could result in air emissions. *See* 40 C.F.R. § 60.5416(c)(1)-(2).

b. Subpart OOOO also requires that the owner/operator maintain records of the results of these inspections. *See* 40 C.F.R. §§ 60.5416(c)(1)-(2), 60.5420(c)(6)-(7).

22. For a storage vessel not subject to a legally and practically enforceable limit on its potential for VOC emissions, the Subpart OOOO emission determination may exclude vapor from the storage vessel that is recovered and routed to a process through a vapor recovery unit designed and operated as specified in Subpart OOOO provided that: (i) the storage vessel meets the cover requirements specified in 40 C.F.R. § 60.5411(b); (ii) the storage vessel meets the closed vent system requirements specified in 40 C.F.R. § 60.5411(c); and (iii) the owner or operator of the storage vessel maintains records that document compliance with the cover requirements specified in 40 C.F.R. § 60.5411(b) and the closed vent system requirements specified in 40 C.F.R. § 60.5411(c) for the storage vessel. *See* 40 C.F.R. § 60.5365(e)(3).

23. If the original emission determination for a storage vessel excluded storage vessel vapor that would be recovered and routed to a process through a vapor recovery unit, the owner or operator must make a new emission determination calculating the storage vessel's potential for VOC emissions within 30 days if: (i) the storage vessel is operated without meeting the cover requirements specified in 40 C.F.R. § 60.5411(b); (ii) the storage vessel is operated without meeting the closed vent system requirements specified in 40 C.F.R. § 60.5411(c); or (iii) the vapor recovery unit is removed. *See* 40 C.F.R. § 60.5365(e)(3)(iv).

24. The cover requirements at 40 C.F.R. § 60.5411(b) require that covers on storage vessels meet certain requirements, including that the cover and all openings on the cover shall form a continuous impermeable barrier over the entire surface area of the liquid in the vessel; each cover opening shall be secured in a closed sealed position except when certain activities are ongoing; and that each storage vessel thief hatch shall be equipped, maintained, and operated with a weighted mechanism or equivalent, to ensure the lid remains properly seated.

25. The closed vent system requirements at 40 C.F.R. § 60.5411(c) require that the closed vent system is designed to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device that meets the requirements of 40 C.F.R. § 60.5412(c) and (d); and to design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual, and auditory inspections.

26. The recordkeeping requirements at 40 C.F.R. § 60.5420(c) require that the owner/operator must maintain the records identified as specified in 40 C.F.R. § 60.7(f) and in paragraphs 40 C.F.R. § 60.5420(c)(1) through (14). All records required by Subpart OOOO must be maintained either onsite or at the nearest local field office for at least five years.

NSPS Subpart OOOOa

27. In 2016, EPA promulgated additional NSPS regulations for the crude oil and natural gas production, transmission, and distribution industry sector, which were codified at Subpart OOOOa. 81 Fed Reg. 35,898 (June 3, 2016).

28. Subpart OOOOa establishes emission standards for the control of VOC, sulfur dioxide emissions, and greenhouse gas emissions in the form of methane from various types of oil and natural gas production, processing, transmission, storage, and distribution equipment constructed, modified, or reconstructed after September 18, 2015, including storage vessels.

29. Subpart OOOOa, at 40 C.F.R. § 60.5430a, defines "storage vessel" as a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of non-earthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support.

30. A storage vessel is an affected facility subject to Subpart OOOOa requirements if construction, modification, or reconstruction of the storage vessel was commenced after September 18, 2015, and if a properly performed emission determination indicates that the storage vessel has the potential for VOC emissions equal to or greater than six (6) tons per year. *See* 40 C.F.R. § 60.5365a(e). A storage vessel meeting these criteria is defined as a "storage vessel affected facility."

31. A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than six (6) tons per year shall remain an affected facility under Subpart OOOOa. *See* 40 C.F.R. § 60.5365a(e)(2).

32. The potential for VOC emissions from a storage vessel must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to August 2, 2016, or within 60 days after startup (whichever was later). *See* 40 C.F.R. §§ 60.5365a(e), 60.5410a(h)(1).

33. In calculating the potential VOC emissions from a storage vessel, the determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local or tribal authority. *See* 40 C.F.R. § 60.5365a(e).

34. Subpart OOOOa requires the owner/operator of a storage vessel affected facility generally either (i) to reduce VOC emissions by 95.0 percent within 60 days after startup; or (ii) after 12 consecutive months of reducing VOC emissions by 95.0 percent, to maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than four (4) tons per year without considering control. *See* 40 C.F.R. § 60.5395a(a)(2)-(3).

35. Subpart OOOOa, at 40 C.F.R. § 60.5415a(e), provides that the owner/operator using a control device or routing emissions to a process for a storage vessel affected facility must

meet the following requirements to demonstrate continuous compliance with 40 C.F.R. § 60.5395a(a)(2):

a. For each storage vessel affected facility, the owner/operator must reduce VOC emissions as specified in 40 C.F.R. § 60.5395a(a)(2) (i.e. by 95.0 percent within 60 days after startup); and

b. For each control device installed to meet the requirements of 40 C.F.R. § 60.5395a(a)(2), the owner/operator must demonstrate continuous compliance with the performance requirements of 40 C.F.R. § 60.5412a(d) for each storage vessel affected facility by: (i) complying with 40 C.F.R. § 60.5416a(c) for each cover and closed vent system; and either (ii) complying with 40 C.F.R. § 60.5417a(h) for each control device; or (iii) operating each closed vent system that routes emissions to a process unit as specified in 40 C.F.R. § 60.5411a(c)(2) and (3).

36. If the original emission determination for a storage vessel excluded storage vessel vapor that would be recovered and routed to a process through a vapor recovery unit, the owner or operator must make a new emission determination calculating the storage vessel's potential for VOC emissions within 30 days if: (i) the storage vessel is operated without meeting the cover requirements specified in 40 C.F.R. § 60.5411a(b); (ii) the storage vessel is operated without meeting the closed vent system requirements specified in 40 C.F.R. § 60.5411a(c) and (d); or (iii) the vapor recovery unit is removed. *See* 40 C.F.R. § 60.5365a(e)(3).

37. The cover requirements at 40 C.F.R. § 60.5411a(b) require that covers on storage vessels meet certain requirements, including that the cover and all openings on the cover shall form a continuous impermeable barrier over the entire surface area of the liquid in the vessel; each cover opening shall be secured in a closed, sealed position except when certain activities are ongoing; and that each storage vessel thief hatch shall be equipped, maintained, and operated with a weighted mechanism or equivalent, to ensure the lid remains properly seated and sealed under normal operating conditions.

38. The closed vent system requirements at 40 C.F.R. § 60.5411a(c) require that the closed vent system is designed to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device that meets the requirements of 40 C.F.R. § 60.5412a(c) and (d); and to design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual, and auditory inspections.

39. The closed vent system requirements at 40 C.F.R. § 60.5411a(d) require the owner/operator to conduct an assessment that the closed system is of sufficient design and capacity to ensure that all emissions from the storage vessel are routed to the control device and that the control device is of sufficient design and capacity to accommodate all emissions from the affected facility and have it certified by a qualified professional engineer in accordance with 40 C.F.R. § 5411a(d)(1)(i) and (ii).

40. Subpart OOOOa, at 40 C.F.R. § 60.5416a(c)(4), provides that, in the event that a leak or defect is detected, the owner/operator must repair the leak or defect as soon as practicable according to the following (except as provided by 40 C.F.R. § 60.5416a(c)(5)): (i) a first attempt at repair must be made no later than five (5) calendar days after the leak is detected; (ii) repair must be completed no later than thirty (30) calendar days after the leak is detected; and (iii) grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

41. Each control device used to comply with the emission reduction standard in 40 C.F.R. § 60.5395a(a)(2) for a storage vessel affected facility must be installed in accordance with 40 C.F.R. § 60.5412a(d)(1) through (4), as applicable. As an alternative to 40 C.F.R. § 60.5412a(d)(1), the owner/operator may install a control device model tested under 40 C.F.R. § 60.5413a(d), which meets the criteria in 40 C.F.R. § 60.5413a(d)(11) and meets the continuous compliance requirements in 40 C.F.R. § 60.5413a(e). *See* 40 C.F.R. § 60.5412a(d).

42. Subpart OOOOa, at 40 C.F.R. § 60.5412a(d)(1)(iii), provides that, for each combustion control device, the owner/operator must operate the device with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22 of appendix A-7 of Subpart OOOOa must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period of the visible emissions test shall be 15 minutes.

43. For each control device used to comply with the emission reduction standard in 40 C.F.R. § 60.5395a(a)(2) for a storage vessel affected facility, the owner/operator must demonstrate continuous compliance according to 40 C.F.R. § 60.5417a(h)(1) through (h)(4). *See* 40 C.F.R. § 60.5417a(h). The owner/operator is exempt from the requirements of 40 C.F.R. § 60.5417a(h) if the owner/operator installs a control device model tested in accordance with 40 C.F.R. § 60.5413a(d)(2) through (10), which meets the criteria in 40 C.F.R. § 60.5413a(d)(11), the reporting requirement in 40 C.F.R. § 60.5413a(d)(12), and the continuous compliance requirement in 40 C.F.R. § 60.5413a(e).

44. Combustion control devices tested by the manufacturer in accordance with 40 C.F.R. § 60.5413a(d) must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22 of appendix A-7 of Subpart OOOOa must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. *See* 40 C.F.R. § 60.5413a(e)(3).

45. A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in 40 C.F.R. § 60.5417a(g)(1) through (6) being met. If the owner/operator monitors multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs 40 C.F.R. § 60.5417a(g)(1) through (6), then a single excursion is determined to have occurred for the control device for that operating day. *See* 40 C.F.R. § 60.5417a(g).

46. Subpart OOOOa, at 40 C.F.R. § 60.5430a, defines "fugitive emissions component" as any component that has the potential to emit fugitive emissions of VOC at a well site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to 40 C.F.R. § 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to 40 C.F.R. § 5395a, compressors, instruments, and meters. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

47. Subpart OOOOa, at 40 C.F.R. § 60.5430a, defines a "well site" as one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards at 40 C.F.R. § 60.5397a, a well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g. centralized tank batteries).

48. Subpart OOOOa, at 40 C.F.R. § 60.5365a(i), provides that the collection of fugitive emissions components at a well site, as defined in 40 C.F.R. § 60.5430a, is an affected facility, except as provided in 40 C.F.R. § 60.5365a(i)(2) (i.e. a well site that only contains one or more wellheads).

49. Subpart OOOOa, at 40 C.F.R. § 60.5415a(h), provides that, for each collection of fugitive emissions components at a well site, the owner/operator must demonstrate continuous compliance with the fugitive emission standards in 40 C.F.R. § 60.5397a according to the following requirements: (i) the owner/operator must conduct periodic monitoring surveys as required in 40 C.F.R. § 60.5397a(g); (ii) the owner/operator must repair or replace each identified source of fugitive emissions as required in 40 C.F.R. § 60.5397a(h); (iii) the owner/operator must maintain records as specified in 40 C.F.R. § 60.5420a(c)(15); and (iv) the owner/operator must submit annual reports for the collection of fugitive emissions components at a well site as required in 40 C.F.R. § 60.5420a(b)(1) and (7).

50. Subpart OOOOa, at 40 C.F.R. § 60.5397a(a), provides that the owner/operator must monitor all fugitive emission components in accordance with paragraphs 40 C.F.R. § 60.5397a(b) through (g). The owner/operator must keep records in accordance with 40 C.F.R. § 60.5397a(i) and report in accordance with 40 C.F.R. § 60.5397a(j). Fugitive emissions are defined in 40 C.F.R. § 60.5397a(a) as: Any visible emission from a fugitive emissions component observed using optical gas imaging or an instrument reading of 500 ppm or greater using EPA Method 21.

51. Subpart OOOOa, at 40 C.F.R. § 60.5397a(b), requires the owner/operator to develop an emissions monitoring plan that covers the collection of fugitive emissions components at well sites with each company-defined area in accordance with 40 C.F.R. § 60.5397a(c) and (d).

52. Subpart OOOOa, at 40 C.F.R. §§ 60.5397a(c) and 60.5397a(d), provides that a fugitive emissions monitoring plan must include the elements specified in 40 C.F.R. § 60.5397a(c)(1) through (8) and the elements specified in 40 C.F.R. § 60.5397a(d)(1)

through (4), at a minimum.

53. Subpart OOOOa, at 40 C.F.R. § 60.5397a(h), provides that each identified source of fugitive emissions shall be repaired or replaced in accordance with 40 C.F.R. § 60.5397a(h)(1) and (2). For fugitive emissions components also subject to the repair provisions of 40 C.F.R. § 60.5416a(b)(9) through (12) and (c)(4) through (7), those provisions apply instead to those closed vent systems and covers, and the repair provisions of 40 C.F.R. § 60.5397a(h)(1) and (2) do not apply to those closed vent systems and covers.

54. Subpart OOOOa, at 40 C.F.R. § 60.5397a(h)(1), provides that each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than thirty (30) calendar days after detection of the fugitive emissions.

55. Subpart OOOOa, at 40 C.F.R. § 60.5397a(h)(3), provides that each repaired or replaced fugitive emissions component must be resurveyed as soon as practicable, but no later than thirty (30) days after being repaired, to ensure that there are no fugitive emissions.

56. Subpart OOOOa, at 40 C.F.R. § 60.5397a(h)(3)(iii), provides that operators that use EPA Method 21 to resurvey the repaired fugitive emissions components are subject to the resurvey provisions specified in Subpart OOOOa, at 40 C.F.R. § 60.5397a(h)(3)(iii)(A) and (B).

57. The recordkeeping requirements at 40 C.F.R. § 60.5420a(c) require that the owner/operator must maintain the records identified as specified in 40 C.F.R. § 60.7(f) and in paragraphs 40 C.F.R. § 60.5420a(c)(1) through (14). All records required by Subpart OOOO must be maintained either onsite or at the nearest local field office for at least five (5) years

Northwest Gas Processing, LLC (NWGP) Permit to Construct

58. Idaho Department of Environmental Quality ("DEQ") issued a Permit to Construct, PTC No. P-2013.0059 Project 61908, on October 27, 2017 (2017 NWGP PTC) for the Northwest Gas Processing Facility. The 2017 NWGP PTC was issued to NWGP. The 2017 NWGP PTC is a modification of and replaces the previous permit identified as PTC No. P-2013.0059 that was issued on April 10, 2015.

59. The 2017 NWGP PTC, at Condition 2.8, provides the facility shall be equipped with a vapor recovery unit system designed to collect the total organic compound vapors displaced from tank trucks during product loading and from the condensate storage tanks.

60. The 2017 NWGP PTC, at Condition 2.61, provides that, in accordance with 40 C.F.R. § 60.482-10a(d), flares used to comply with 40 C.F.R. Part 60, Subpart VVa shall comply with the requirements of 40 C.F.R. § 60.18.

61. The 2017 NWGP PTC, at Condition 2.147, provides that, in accordance with 40 C.F.R. § 60.5420(c), the permittee must maintain the records identified as specified in 40 C.F.R. § 60.7(f) and as identified at 40 C.F.R. § 60.5420(c)(1) and (4). All such records must be maintained either onsite or at the nearest local field office for at least five (5) years.

62. The 2017 NWGP PTC, at Condition 4.10, provides that the permittee shall maintain sufficient records to ensure compliance with all of the terms and conditions of the permit. All monitoring records and support information shall be retained for a period of at least five (5) years from the date of the monitoring sample, measurement, report, or application.

Little Willow Road Gathering Station Permit to Construct

63. Idaho DEQ issued a Permit to Construct, PTC No. P-2015.0015 Project 61636, on February 22, 2016 (2016 Little Willow PTC) for Alta Mesa' Little Willow Gathering Station. The 2016 Little Willow PTC was issued to Alta Mesa Services, LP ("Alta Mesa Services"). The 2016 Little Willow PTC is a modification of and replaces the previous permit identified as PTC No. P-2015.0015 that was issued on November 18, 2015.

64. The 2016 Little Willow PTC, at Condition 2.6, provides the facility shall be equipped to collect the total organic compound vapors displaced from tank trucks during loading and from the oil tanks.

65. The 2016 Little Willow PTC, at Condition 2.8, provides the permittee shall conduct a quarterly facility-wide inspection of potential sources of visible emissions. The permittee shall maintain records of the results of each visible emission inspection and each opacity test when conducted.

66. The 2016 Little Willow PTC, at Condition 4.10, provides that the permittee shall maintain sufficient records to ensure compliance with all of the terms and conditions of this permit. All monitoring records and support information shall be retained for a period of at least five (5) years from the date of the monitoring sample, measurement, report, or application.

Relevant Factual Background

67. Alta Mesa Services is incorporated in the State of Texas and was authorized to do business in the State of Idaho during the time period relevant to the violations of Subparts OOOO and OOOOa and the 2016 Little Willow and 2017 NWGP PTCs described below.

68. NWGP is incorporated in the State of Delaware and does business in the State of Idaho.

69. High Mesa Services, LLC ("High Mesa") is incorporated in the State of Delaware and does business in the State of Idaho.

70. Alta Mesa Services, NWGP, and High Mesa maintain corporate offices located at 15021 Katy Freeway, Suite 400, Houston, Texas.

71. Alta Mesa Services, NWGP, and High Mesa are "persons" within the meaning of Section 302(e) of the CAA, 42 U.S.C. § 7602(e).

72. During the time period relevant to the violations of Subparts OOOO and OOOOa and the 2016 Little Willow PTC described below, Alta Mesa Services, NWGP, and/or High

Mesa owned or operated the Little Willow Road Gathering Station located at 4649 Little Willow Road, New Plymouth, Idaho (Little Willow Station).

73. During the time period relevant to the violations of Subpart OOOO and the 2017 NWGP PTC described below, Alta Mesa Services, NWGP, and/or High Mesa owned or operated the Northwest Gas Processing Facility located at 4303 Highway 30 South, New Plymouth, Idaho (NWGP Facility).

74. NWGP and/or High Mesa currently owns and operates Little Willow Station and the NWGP Facility.

75. During the time period relevant to the violations of Subparts OOOO and OOOOa and the 2016 Little Willow PTC and 2017 NWGP PTC described below, Alta Mesa Services, NWGP, and/or High Mesa owned and operated several oil and natural gas well pads in Adams county in Idaho. NWGP and/or High Mesa currently owns and operates such wells. Production fluids collected at the well pads are transferred to the Little Willow Station, where gas, oil, and water are separated.

76. The term "Alta Mesa," as used in the remaining allegations and the violations of Subparts OOOO and OOOOa and the 2016 Little Willow PTC described below, refers to Alta Mesa Services, NWGP, and/or High Mesa.

77. The Little Willow Station was issued the 2016 Little Willow PTC on February 22, 2016, for modifications to equipment at the facility.

78. The NWGP Facility was issued the 2017 NWGP PTC on October 27, 2017, for modifications to equipment at the facility.

79. On July 10-11, 2018, EPA staff inspected and observed the Little Willow Station and NWGP Facility.

80. The NWGP Facility includes storage vessels that contain an accumulation of condensate, and that are constructed primarily of non-earthen materials.

81. The Little Willow Station includes storage vessels that contain an accumulation of crude oil and produced water, and that are constructed primarily of non-earthen materials. In addition, the Little Willow Station is a separate tank battery surface site collecting crude oil and produced water from wells not located at Little Willow Station.

82. The storage vessels at the NWGP Facility were all constructed after April 12, 2013 but before September 18, 2015.

83. The storage vessels at Little Willow Station were either constructed (i) between August 23, 2011 and on or before September 18, 2015; or (ii) after September 18, 2015.

84. The storage vessels at the NWGP Facility and Little Willow Station all had the potential for VOC emissions equal to or greater than six (6) tons per year for a 30-day period of production prior to the applicable emission determination deadline as specified in Subparts OOOO and OOOOa.

85. On information and belief, the vapor recovery unit is not designed to collect the total organic compound vapor from storage vessels at the NWGP Facility.

86. On information and belief, the vapor combustor is not designed to collect the total organic compound vapors from the storage vessels at the Little Willow Station.

87. The 2017 NWGP PTC issued for the NWGP Facility and the 2016 Little Willow PTC issued for Little Willow Station include no legally and practically enforceable voluntary limits to restrict the potential VOC emissions from each storage vessel to less than six (6) tons per year.

88. During the July 2018 inspection, EPA inspectors detected emissions from pressure relief devices on nine of ten storage vessels at the NWGP Facility. EPA inspectors also detected emissions at a check valve located on the closed vent system used to route emissions from the storage vessels at the NWGP Facility.

89. During the July 2018 inspection, at the NWGP Facility, EPA inspectors observed large quantities of uncombusted hydrocarbon emissions leaving the flare. EPA inspectors requested information regarding operation of the flare, including a description of operations at the on-site flares, the net heating value of vent gas being sent to the flare, and the hydrogen content and exit velocity of the gas stream for the time period of the July 2018 inspection. Alta Mesa did not provide this information.

90. During the July 2018 inspection, EPA inspectors detected emissions from pressure relief devices on six produced water storage vessels and one oil storage vessel at the Little Willow Station.

91. Records of optical gas imaging inspections for Little Willow Station's produced water tanks and crude oil tank from June 25, 2018 were collected by EPA inspectors as part of the July 2018 inspection. The inspection records show that each of the pressure relief devices were found leaking on June 25, 2018. The inspection records also show that the pressure relief devices were not resurveyed in accordance with EPA Method 21.

92. Based on correspondence with Alta Mesa staff in August 2018, the pressure relief devices identified in Paragraphs 90 and 91 were not repaired within 30 days.

93. During the July 2018 inspection, EPA inspectors observed visible emissions from the vapor combustor used to control emissions from the six oil storage vessels at the Little Willow Station. Visible emissions were observed for at least three minutes and over the duration of the site visit.

94. During the July 2018 inspection, for the Little Willow Station, EPA inspectors requested three months of EPA Method 22 inspection records for the vapor combustor. Alta Mesa did not provide the requested records during or following the July 2018 inspection.

95. During the July 2018 inspection, for the Little Willow Station, EPA inspectors requested the site-specific fugitive emissions monitoring plan. Alta Mesa did not provide the document during the inspection. Following the inspection, on August 13, 2018, Alta Mesa provided an incomplete fugitive emissions monitoring plan for the Little Willow Station.

96. In April 2019, EPA issued to Alta Mesa an information request under Section 114 of the CAA (2019 Information Request). EPA requested, among other things, emissions evaluations of the storage vessels, operation records for air pollution control devices, visible emission inspection records, equipment leak repair records, closed vent system inspection records, and other records required to demonstrate compliance with permit requirements and Subparts OOOO and OOOOa, as applicable, from both the Little Willow Station and the NWGP Facility.

97. Alta Mesa did not submit documents responsive to EPA's 2019 Information Request.

Little Willow Violations

98. Alta Mesa's failure to provide EPA with information requested in the 2019 Information Request constitutes a violation of the recordkeeping, inspections, monitoring, and entry provision at Section 114(a) of the CAA, U.S.C. § 7414(a).

99. Alta Mesa's failure to provide EPA with information requested during the July 2018 inspection constitutes a failure to maintain records required by Subpart OOOOa onsite or at the nearest local field office for at least five years, violating (i) 40 C.F.R. §§ 60.5420a(c) and 60.5420(c) and Section 111 of the CAA, 42 U.S.C. § 7411; and (ii) 2016 Little Willow PTC Condition 4.10 and Section 110 of the CAA, 42 U.S.C. § 7410.

100. Based on Alta Mesa's original emission determination for the storage vessels at the Little Willow Station, Alta Mesa failed to correctly calculate Subparts OOOO and OOOOa emission determinations, violating the requirements of 40 C.F.R. §§ 60.5365(e) and 60.5365a(e) and Section 111 of the CAA, 42 U.S.C. § 7411.

101. Alta Mesa did not make a Subparts OOOO and OOOOa initial notification for each storage vessel affected facility at the Little Willow Station. Alta Mesa has thereby violated requirements of 40 C.F.R. §§ 60.5420(b)(6) and Section 111 of the CAA, 42, U.S.C. § 7411.

102. Alta Mesa has not submitted Subpart OOOO and OOOOa annual reports for each storage vessel affected facility at the Little Willow Station. Alta Mesa has thereby violated and continues to violate requirements of 40 C.F.R. §§ 60.5420(b)(6) and 60.5420a(b)(6) and Section 111 of the CAA, 42 U.S.C. § 7411.

103. Alta Mesa has not performed periodic Subparts OOOO and OOOOa inspections of each storage vessel affected facility's cover and closed vent system at the Little Willow Station. Alta Mesa has thereby violated and continues to violate requirements of 40 C.F.R. §§ 60.5416(c) and 60.5416a(c) and Section 111 of the CAA, 42 U.S.C. § 7411.

104. Alta Mesa has not maintained required records regarding Subparts OOOO and OOOOa compliance for each storage vessel affected facility at the Little Willow Station, including records documenting compliance with the cover requirements and closed vent system requirements specified in 40 C.F.R. §§ 60.5411(b)-(c) and 60.5411a(b)-(c). Alta Mesa has thereby violated requirements of 40 C.F.R. §§ 60.5410(h) and 60.5420(c); 40 C.F.R. §§ 60.5410a(h) and 60.5420a(c); and Section 111 of the CAA, 42 U.S.C. § 7411.

105. Alta Mesa has not maintained continuous compliance with the Subparts OOOO and OOOOa emission control requirements applicable to each storage vessel at the Little Willow Station, including cover and closed vent system design and operation requirements. Alta Mesa has thereby violated and continues to violate requirements of 40 C.F.R. §§ 60.5395(c)and (e), 60.5411(b) and (c); 40 C.F.R. §§ 60.5395a(b) and (e), 60.5411a(b) and (c); and Section 111 of the CAA, 42 U.S.C. § 7411.

106. Alta Mesa's storage vessels at the Little Willow Station are affected facilities under Subparts OOOO and OOOOa, and based on the above described detectable emissions from storage vessels observed by EPA staff, Alta Mesa has failed to ensure that the covers on its storage vessels meet certain requirements, including that the covers and all openings shall form a continuous impermeable barrier over the entire surface area of the liquid in the vessel, and that each cover opening shall be secured in a closed, sealed position except when certain activities are ongoing. Alta Mesa has thereby violated and continues to violate the requirements of 40 C.F.R. §§ 60.5411(b) and 60.5411a(b) and Section 111 of the CAA, 42 U.S.C. § 7411.

107. Based on the above described detectable emissions from storage vessels observed by EPA staff, Alta Mesa has failed to design its closed vent systems to route all gases, vapors, and fumes emitted from the material in the storage vessels to a control device, and to design and operate closed vent systems with no detectable emissions, as determined using olfactory, visual, and auditory inspections. Alta Mesa has thereby violated and continues to violate the requirements of 40 C.F.R. §§ 60.5411(c) and 60.5411a(c) and Section 111 of the CAA, 42 U.S.C. § 7411.

108. Based on the above described detectable emissions from storage vessels observed by EPA staff, Alta Mesa has failed to design its vapor combustor system to collect the total organic compound vapors displaced from the oil storage tanks. Alta Mesa has thereby violated and continues to violate the requirements of 2016 Little Willow PTC Condition 2.6.

109. Based on, among other things, Alta Mesa's failure to meet certain cover, closed vent and control device requirements, demonstrated by the above described detectable emissions from storage vessels observed by EPA staff, Alta Mesa has failed to demonstrate initial compliance at the storage vessel affected facilities at the NWGP Facility. Alta Mesa has thereby

violated and continues to violate the requirements of 40 C.F.R. §§ 60.5410(h) and 60.5410a(h) and Section 111 of the CAA, 42 U.S.C. § 7411.

110. Alta Mesa's failure to develop an emissions monitoring plan that covers the collection of fugitive emissions components, by August 2, 2016 or upon initial startup, whichever is later, is a violation of 40 C.F.R. § 60.5397(b) and 60.5410(j)(1); 40 C.F.R. § 60.5397a(b) and 60.5410a(j)(1); and Section 111 of the CAA, 42 U.S.C. § 7411.

111. Alta Mesa's failure to develop an emissions monitoring plan that covers the collection of fugitive emissions components at Little Willow Station and that includes the elements specified in 40 C.F.R. § 60.5397a(c)(1)-(8) and 60.5397a(d)(1)-(4) is a violation of 40 C.F.R. § 60.5397a(c) and (d) and Section 111 of the CAA, 42 U.S.C. § 7411.

112. Alta Mesa failed to repair or replace each identified source of fugitive emissions as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions, in violation of 40 C.F.R. § 60.5397a(h).

113. Alta Mesa failed to repair or replace each identified leak as soon as practicable, but no later than 30 calendar days after detection of the leak, in violation of 40 C.F.R. § 60.5416a(c)(4).

114. Alta Mesa failed to resurvey each repaired or replaced fugitive emissions component as soon as practicable to ensure there are no fugitive emissions, in violation of 40 C.F.R. § 60.5397a(h)(3).

115. Alta Mesa failed to conduct inspections to monitor for visible emissions at each combustion device at least once every calendar month, in violation of Subpart OOOOa at 40 C.F.R. § 60.5417a(h) and (h)(1)(ii).

116. Alta Mesa's oil storage vessels at the Little Willow Station are subject to Subpart OOOOa, and based on Alta Mesa's failure to operate its combustion control devices with no visible emissions, Alta Mesa has violated and continues to violate 40 C.F.R. § 60.5412a(d)(1)(iii) or 40 C.F.R. § 60.5417a(h) and 40 C.F.R. § 60.5413a(e)(3).

NWGP Facility Violations

117. Alta Mesa's failure to provide EPA with information requested in the 2019 Information Request constitutes a violation of the recordkeeping, inspections, monitoring, and entry provision at Section 114(a) of the CAA, U.S.C. § 7414(a).

118. Alta Mesa failed to provide EPA with information requested during the July 2018 inspection and therefore failed to maintain records required by Subpart OOOO onsite or at the nearest local field office for at least five years, violating 40 C.F.R. § 60.5420(c) and Section 111 of the CAA, 42 U.S.C. § 7411; and 2017 NWGP PTC Conditions 2.147 and 4.10 and Section 110 of the CAA, 42 U.S.C. § 7410.

119. Based on Alta Mesa's original emission determination for the storage vessels at the NWGP Facility, Alta Mesa failed to correctly calculate its Subpart OOOO emission determination, violating the requirements of 40 C.F.R. § 60.5365(e) and Section 111 of the CAA, 42 U.S.C. § 7411.

120. If Alta Mesa's original emission determination for the storage vessels at the NWGP Facility excluded storage vessel vapor that would be recovered and routed to a process through a vapor recovery unit, then by failing to make a Subpart OOOO emission determination for each storage vessel at the NWGP Facility after the storage vessel was operated without meeting: (i) the cover requirements specified in 40 C.F.R. § 60.5411(b); and/or (ii) the closed vent system requirements specified in 40 C.F.R. § 60.5411(c), Alta Mesa violated the requirements of 40 C.F.R. § 60.5365(e)(3) and Section 111 of the CAA, 42 U.S.C. § 7411.

121. Alta Mesa did not make a Subpart OOOO initial notification for each storage vessel affected facility at the NWGP Facility. Alta Mesa has thereby violated requirements of 40 C.F.R. § 60.5420(b)(6) and Section 111 of the CAA, 42, U.S.C. § 7411.

122. Alta Mesa has not submitted Subpart OOOO annual reports for each storage vessel affected facility at the NWGP Facility. Alta Mesa has thereby violated and continues to violate the requirements of 40 C.F.R. § 60.5420(b)(6) and Section 111 of the CAA, 42 U.S.C. § 7411.

123. Alta Mesa has not performed periodic Subpart OOOO inspections of each storage vessel affected facility's cover and closed vent system at the NWGP Facility. Alta Mesa has thereby violated and continues to violate the requirements of 40 C.F.R. § 60.5416(c) and Section 111 of the CAA, 42 U.S.C. § 7411.

124. Alta Mesa has not maintained required records regarding Subpart OOOO compliance for each storage vessel affected facility at the NWGP Facility, including records documenting compliance with the cover requirements and closed vent system requirements specified in 40 C.F.R. § 60.5411(b)-(c). Alta Mesa has thereby violated requirements of 40 C.F.R. §§ 60.5410(h) and 60.5420(c) and Section 111 of the CAA, 42 U.S.C. § 7411.

125. If Alta Mesa's original emission determination for the storage vessel excluded storage vessel vapor that would be recovered and routed to a process through a vapor recovery unit, then Alta Mesa's failure to maintain required records violated the requirements of 40 C.F.R. § 60.5365(e)(3)(iii) and Section 111 of the CAA, 42 U.S.C. § 7411.

126. Alta Mesa has not maintained continuous compliance with the Subpart OOOO emission control requirements applicable to each storage vessel at the NWGP Facility, including cover and closed vent system design and operation requirements. Alta Mesa has thereby violated and continues to violate the requirements of 40 C.F.R. §§ 60.5395(c) and (e), 60.5411(b) and (c), and Section 111 of the CAA, 42 U.S.C. § 7411.

127. Alta Mesa's storage vessels at the NWGP Facility are affected facilities under Subpart OOOO, and based on the above described detectable emissions from storage vessels

observed by EPA staff, Alta Mesa has failed to ensure that the covers on its storage vessels meet certain requirements, including that the covers and all openings shall form a continuous impermeable barrier over the entire surface area of the liquid in the vessel, and that each cover opening shall be secured in a closed, sealed position except when certain activities are ongoing. Alta Mesa has thereby violated and continues to violate the requirements of 40 C.F.R. § 60.5411(b) and Section 111 of the CAA, 42 U.S.C. § 7411.

128. Based on the above described detectable emissions from storage vessels observed by EPA staff, Alta Mesa has failed to design its closed vent systems to route all gases, vapors, and fumes emitted from the material in the storage vessels to a control device, and to design and operate closed vent systems with no detectable emissions, as determined using olfactory, visual, and auditory inspections. Alta Mesa has thereby violated and continues to violate the requirements of 40 C.F.R. § 60.5411(c) and Section 111 of the CAA, 42 U.S.C. § 7411.

129. Based on the above described detectable emissions from storage vessels observed by EPA staff, Alta Mesa has failed to design its vapor recovery unit system to collect the total organic compound vapors displaced from the condensate storage tanks. Alta Mesa has thereby violated and continues to violate the requirements of 2017 NWGP PTC Condition 2.8.

130. Based on, among other things, Alta Mesa's failure to meet certain cover, closed vent and control device requirements, demonstrated by the above described detectable emissions from storage vessels observed by EPA staff, Alta Mesa has failed to demonstrate initial compliance at the storage vessel affected facilities at the NWGP Facility. Alta Mesa has thereby violated and continues to violate the requirements of 40 C.F.R. § 60.5410(h) and Section 111 of the CAA, 42 U.S.C. § 7411.

Environmental Impact of Violations

131. These violations have caused or can cause excess emissions of VOC and methane.

132. Excess VOC emissions can cause eye, nose, and throat irritation, headaches, loss of coordination, nausea and damage to liver, kidney and the central nervous system.

133. VOC emissions are a precursor to ground-level ozone. Breathing ozone contributes to a variety of health problems including chest pain, coughing, throat irritation and congestion. It can worsen bronchitis, emphysema, and asthma. Ground-level ozone also can reduce lung function and inflame lung tissue.

134. Methane is a potent greenhouse gas, and emissions of methane contribute to climate change.

1/7/2020
Date

Edward Kowalski
Director
Enforcement and Compliance Assurance Division

STATE OF IDAHO
DEPARTMENT OF
ENVIRONMENTAL QUALITY

1410 North Hilton • Boise, Idaho 83706 • (208) 373-0502
www.deq.idaho.gov

C.L. "Butch" Otter, Governor
John H. Tippets, Director

October 27, 2017

David McClure, VP of Facilities and Midstream
Northwest Gas Processing, LLC
15021 Katy Freeway, Suite 400
Houston, TX 77094

RE: Facility ID No. 075-00021, Northwest Gas Processing, LLC, New Plymouth
Final Permit Letter

Dear Mr. McClure:

The Department of Environmental Quality (DEQ) is issuing Permit to Construct (PTC) No. P-2013.0059 Project 61908 to Northwest Gas Processing, LLC located at New Plymouth for the addition of three engines, two heaters, and conversion of two flares from emergency to process use. This PTC is issued in accordance with IDAPA 58.01.01.200 through 228 (Rules for the Control of Air Pollution in Idaho) and is based on the certified information provided in your PTC application received June 13, 2017.

This permit is effective immediately replaces PTC No. P-2013.0059, issued on April 10, 2015. This permit does not release Northwest Gas Processing, LLC from compliance with all other applicable federal, state, or local laws, regulations, permits, or ordinances.

Pursuant to the Construction and Operation Notification General Provision of your permit, it is required that construction and operation notification be provided. Please provide this information as listed to DEQ's Boise Regional Office, 1445 N. Orchard, Boise, ID 83706 Fax (208) 373-0287.

In order to fully understand the compliance requirements of this permit, DEQ highly recommends that you schedule a meeting with J.R. Fuentes, Title V Source Inspector, at (208) 373-0550 to review and discuss the terms and conditions of this permit. Should you choose to schedule this meeting, DEQ recommends that the following representatives attend the meeting: your facility's plant manager, responsible official, environmental contact, and any other staff responsible for day-to-day compliance with permit conditions.

Pursuant to IDAPA 58.01.23, you, as well as any other entity, may have the right to appeal this final agency action within 35 days of the date of this decision. However, prior to filing a petition for a contested case, I encourage you to contact Kelli Wetzel at (208) 373-0502 or kelli.wetzel@deq.idaho.gov to address any questions or concerns you may have with the enclosed permit.

Sincerely,

Mike Simon
Stationary Source Program Manager
Air Quality Division

MS\KW
VP1299
Permit No. P-2013.0059 PROJ 61908

Printed on Recycled Paper

AIR QUALITY

PERMIT TO CONSTRUCT

Permittee	Northwest Gas Processing (NWGP), LLC
Permit Number	P-2013.0059
Project ID	61908
Facility ID	075-00021
Facility Location	4303 Highway 30 South New Plymouth, ID 83661

Permit Authority

This permit (a) is issued according to the "Rules for the Control of Air Pollution in Idaho" (Rules), IDAPA 58.01.01.200–228; (b) pertains only to emissions of air contaminants regulated by the State of Idaho and to the sources specifically allowed to be constructed or modified by this permit; (c) has been granted on the basis of design information presented with the application; (d) does not affect the title of the premises upon which the equipment is to be located; (e) does not release the permittee from any liability for any loss due to damage to person or property caused by, resulting from, or arising out of the design, installation, maintenance, or operation of the proposed equipment; (f) does not release the permittee from compliance with other applicable federal, state, tribal, or local laws, regulations, or ordinances; and (g) in no manner implies or suggests that the Idaho Department of Environmental Quality (DEQ) or its officers, agents, or employees assume any liability, directly or indirectly, for any loss due to damage to person or property caused by, resulting from, or arising out of design, installation, maintenance, or operation of the proposed equipment. Changes in design, equipment, or operations may be considered a modification subject to DEQ review in accordance with IDAPA 58.01.01.200–228.

Date Issued October 27, 2017

Kelli Wetzel

Kelli Wetzel, Permit Writer

Mike Simon

Mike Simon, Stationary Source Manager

Contents

1 Permit Scope 3
2 Natural Gas and Hydrocarbon Treatment Facility 5
3 Compressor Engines 40
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1 Permit Scope

Purpose

1.1 This permit is a modified permit to construct (PTC). This permit revision provides for the installation and operating of three additional compressor engines and two heaters and to convert two existing flares from emergency use to process use.

1.2 This PTC replaces Permit to Construct No. P-2013.0059, issued on April 10, 2015.

Regulated Sources

Table 1.1 lists all sources of regulated emissions in this permit.

Table 1.1 Regulated Sources

Permit Section	Source	Control Equipment
2	2 Reboilers Rated capacity: 0.75 MMBtu/hr each Allowable fuel type: natural gas only	None
2	2 Stabilizer Reboiler Heaters Rated capacity: 1.5 MMBtu/hr Allowable fuel type: natural gas only	None
2	2 Engine Heaters Rated capacity: 0.2 MMBtu/hr Allowable fuel type: natural gas only	None
2	2 Condensate Heaters Rated capacity: 1.5 MMBtu/hr each Allowable fuel type: natural gas only	None
2	2 Flares (one high pressure and one low pressure) Throughput: 126,000 scf/day each	None (considered an emission control device with a control efficiency of 98%)
2	10 Condensate Storage Tanks Throughput: 1800 bbl/day Fuel: Crude Oil RVP10	VRU System Control Efficiency 98.0%
2	Tank Truck Loading	VRU System Control Efficiency 98.0%
3	Compressor Engine 1 Manufacturer: Caterpillar Model: G398 TA HCR Manufacture Date: Unknown Max Capacity: 610 bhp Allowable fuel type: natural gas only	NSCR
3	Compressor Engine 2 Manufacturer: Caterpillar Model: G398 TA HCR Manufacture Date: Unknown Max Capacity: 610 bhp Allowable fuel type: natural gas only	NSCR may be utilized as required to meet the requirements of 40 CFR 63 Subpart ZZZZ

Permit Section	Source	Control Equipment
3	Compressor Engine 3 Manufacturer: Caterpillar Model: G3516B Manufacture Date: Unknown Max Capacity: 1380 bhp Allowable fuel type: natural gas only	NSCR may be utilized as required to meet the requirements of 40 CFR 63 Subpart ZZZZ
3	Compressor Engine 4 Manufacturer: Caterpillar Model: G398 TA HCR Manufacture Date: Unknown Max Capacity: 203 bhp Allowable fuel type: natural gas only	None

[October 27, 2017]

2 Natural Gas and Hydrocarbon Treatment Facility

2.1 Process Description

The NWGP Highway 30 Treating Facility processes raw natural gas and natural gas condensate for delivery to a nearby Williams Northwest natural gas pipeline.

Raw gas enters the plant through a gathering line. Liquids are separated from the gas and the gas is then cooled using propane refrigerant. The gas is then separated from the condensed natural gas liquids and warmed. The gas is compressed to pipeline pressure, passes through a filter, and is delivered to the pipeline.

2.2 Control Device Descriptions

Table 2.1 Natural Gas and Hydrocarbon Treatment Facility Description

Emissions Units / Processes	Control Devices
2 Reboilers	None
2 Stabilizer Reboiler Heaters	None
2 Engine Heaters	None
2 Condensate Heaters	None
2 Flares	None
10 Condensate Storage Tanks	VRU System
Tank Truck Loading	VRU System

[October 27, 2017]

Emission Limits

2.3 Emission Limit

The permittee shall not discharge to the atmosphere from any fuel burning equipment with a maximum rated input of ten million BTU per hour or more, PM in excess of 0.015 gr/dscf corrected to 3% oxygen, in accordance with IDAPA 58.01.01.676-677.

2.4 Opacity Limit

Emissions from the any stack, vent, or functionally equivalent opening shall not exceed 20% opacity for a period or periods aggregating more than three minutes in any 60-minute period as required by IDAPA 58.01.01.625. Opacity shall be determined by the procedures contained in IDAPA 58.01.01.625.

2.5 Flare Particulate Matter Emissions Limit

Particulate matter (PM) emissions from each flare shall not exceed 0.2 pounds per 100 pounds of fuel burned, as required by IDAPA 58.01.01.785.

[February 5, 2015]

Operating Requirements

2.6 Fuel Type Restriction

All fuel burning equipment listed in Table 2.1 shall be fired on natural gas exclusively.

2.7 Flare Pilot Flame

A pilot flame must be present at both flares.

[October 27, 2017]

2.8 Vapor Recovery Unit

The facility shall be equipped with a vapor recovery unit system designed to collect the total organic compound vapors displaced from tank trucks during product loading and from the condensate storage tanks.

[October 27, 2014]

2.9 Reasonable Control of Fugitive Emissions

All reasonable precautions shall be taken to prevent particulate matter (PM) from becoming airborne in accordance with IDAPA 58.01.01.650-651. In determining what is reasonable, considerations will be given to factors such as the proximity of dust-emitting operations to human habitations and/or activities and atmospheric conditions that might affect the movement of PM. Some of the reasonable precautions include, but are not limited to, the following:

- Use, where practical, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads, or the clearing of lands.
- Application, where practical, of asphalt, oil, water, or suitable chemicals to, or covering of, dirt roads, material stockpiles, and other surfaces which can create dust.
- Installation and use, where practical, of hoods, fans, and fabric filters or equivalent systems to enclose and vent the handling of dusty materials. Adequate containment methods should be employed during sandblasting or other operations.
- Covering, where practical, of open-bodied trucks transporting materials likely to give rise to airborne dusts. Paving of roadways and their maintenance in a clean condition, where practical.
- Prompt removal of earth or other stored material from streets, where practical.

Monitoring and Recordkeeping Requirements

2.10 Opacity Monitoring

The permittee shall conduct a quarterly facility-wide inspection of potential sources of visible emissions, during daylight hours and under normal operating conditions. The inspection shall consist of a see/no see evaluation for each potential source of visible emissions. If any visible emissions are present from any point of emission, the permittee shall either

a) take appropriate corrective action as expeditiously as practicable to eliminate the visible emissions. Within 24 hours of the initial see/no see evaluation and after the corrective action, the permittee shall conduct a see/no see evaluation of the emissions point in question. If the visible emissions are not eliminated, the permittee shall comply with b).

or

b) perform a Method 9 opacity test in accordance with the procedures outlined in IDAPA 58.01.01.625. A minimum of 30 observations shall be recorded when conducting the opacity test. If opacity is greater than 20%, as measured using Method 9, for a period or periods aggregating more than three minutes in any 60-minute period, the permittee shall take all necessary corrective action and report the exceedance in accordance with IDAPA 58.01.01.130-136.

The permittee shall maintain records of the results of each visible emission inspection and each opacity test when conducted. The records shall include, at a minimum, the date and results of each inspection and test and a description of the following: the permittee's assessment of the conditions existing at the time visible emissions are present (if observed), any corrective action taken in response to the visible emissions, and the date corrective action was taken.

2.11 Responsible Control Measures

The permittee shall conduct a quarterly facility-wide inspection of potential sources of fugitive PM emissions, during daylight hours and under normal operating conditions, to ensure that the methods used to reasonably control fugitive emissions are effective. If fugitive emissions are not being reasonably controlled, the permittee shall take corrective action as expeditiously as practicable. The permittee shall maintain records of the results of each fugitive emissions inspection. The records shall include, at a minimum, the date of each inspection and a description of the following: the permittee's assessment of the conditions existing at the time fugitive emissions were present (if observed), any corrective action taken in response to the fugitive emissions, and the date the corrective action was taken. A compilation of the most recent five years of records shall be kept onsite and made available to DEQ representatives upon request.

Federal Requirements

40 CFR 60 Subpart OOOO Requirements

"Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution"

2.12 In accordance with 40 CFR 60.5370, the permittee must be in compliance with the standards of this subpart no later than October 15, 2012 or upon startup, whichever is later.

2.13 In accordance with 40 CFR 60.5400(a), the permittee must comply with the requirements of §§60.482-1a(a), (b), and (d), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401 for the group of all equipment, except compressors, within a process unit.

2.14 In accordance with 40 CFR 60.482-1a(a), the permittee must demonstrate compliance with the requirements of §§60.482-1a through 60.482-10a or §60.480a(e) for all equipment within 180 days of initial startup.

2.15 In accordance with 40 CFR 60.482-1a(b), compliance will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485a.

2.16 In accordance with 40 CFR 60.482-1a(d), equipment that is in vacuum service is excluded from the requirements of §§60.482-2a through 60.482-10a if it is identified as required in §60.486a(e)(5).

2.17 In accordance with 40 CFR 60.482-2a(a)(1), each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in §60.485a(b), except as provided in §60.482-1a(c) and (f) and paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in §60.482-1a(c) and paragraphs (d), (e), and (f) of this section.

2.18 In accordance with 40 CFR 60.482-2a(a)(2), each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in §60.482-1a(f).

2.19 In accordance with 40 CFR 60.482-2a(b)(1), the instrument reading that defines a leak is specified below:

- 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;
- 2,000 ppm or greater for all other pumps.

2.20 In accordance with 40 CFR 60.482-2a(b)(2), if there are indications of liquids dripping from the pump seal, the permittee shall follow the procedure below. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified, whichever is applicable.

- Monitor the pump within 5 days as specified in §60.485a(b). A leak is detected if the instrument reading measured during monitoring indicates a leak. The leak shall be repaired using the procedures in paragraph (c) of this section.
- Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

2.21 In accordance with 40 CFR 60.482-2a(c)(1), when a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9a.

2.22 In accordance with 40 CFR 60.482-2a(c)(2), a first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described below, where practicable.

- Tightening the packing gland nuts;
- Ensuring that the seal flush is operating at design pressure and temperature.

2.23 In accordance with 40 CFR 60.482-2a(d), each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified below are met.

- Each dual mechanical seal system is:
    - Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or
    - Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482-10a; or
    - Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.
- The barrier fluid system is in heavy liquid service or is not in VOC service.
- Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.
- Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.
    - If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.
        - Monitor the pump within 5 days as specified in §60.485a(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.
        - Designate the visual indications of liquids dripping as a leak.
- Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.
    - The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.
    - If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.
- When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

- A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.
- A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

2.24 In accordance with 40 CFR 60.482-2a(e), any pump that is designated, as described in §60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

- Has no externally actuated shaft penetrating the pump housing;
- Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in §60.485a(c); and
- Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

2.25 In accordance with 40 CFR 60.482-2a(f), if any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of §60.482-10a, it is exempt from paragraphs (a) through (e) of this section.

2.26 In accordance with 40 CFR 60.482-2a(g), any pump that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

- The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and
- The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

2.27 In accordance with 40 CFR 60.482-2a(h), any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

2.28 In accordance with 40 CFR 60.482-4a(a), except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in §60.485a(c).

2.29 In accordance with 40 CFR 60.482-4a(b), after each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in §60.482-9a.

- No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in §60.485a(c).

2.30 In accordance with 40 CFR 60.482-4a(c), any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in §60.482-10a is exempted from the requirements of paragraphs (a) and (b) of this section.

2.31 In accordance with 40 CFR 60.482-4a(d), any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements below.

- After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in §60.482-9a.

2.32 In accordance with 40 CFR 60.482-5a(a), each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in §60.482-1a(c) and paragraph (c) of this section.

2.33 In accordance with 40 CFR 60.482-5a(b), each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified below.

- Gases displaced during filling of the sample container are not required to be collected or captured.
- Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.
- Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.
- Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either paragraph below.
    - Return the purged process fluid directly to the process line.
    - Collect and recycle the purged process fluid to a process.
    - Capture and transport all the purged process fluid to a control device that complies with the requirements of §60.482-10a.
    - Collect, store, and transport the purged process fluid to any of the following systems or facilities:
        - A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;
        - A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266;
        - A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261;
        - A waste management unit subject to and operated in compliance with the treatment requirements of 40 CFR 61.348(a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of 40 CFR 61.343

through 40 CFR 61.347; or

- A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR part 279, subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR part 261.

2.34 In accordance with 40 CFR 60.482-5a(c), in-situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

2.35 In accordance with 40 CFR 60.482-6a(a), each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in §60.482-1a(c) and paragraphs (d) and (e) of this section.

- The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

2.36 In accordance with 40 CFR 60.482-6a(b), each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

2.37 In accordance with 40 CFR 60.482-6a(c), when a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

2.38 In accordance with 40 CFR 60.482-6a(d), open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a), (b), and (c) of this section.

2.39 In accordance with 40 CFR 60.482-6a(e), open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

2.40 In accordance with 40 CFR 60.482-7a(a), each valve shall be monitored monthly to detect leaks by the methods specified in §60.485a(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g),and (h) of this section, §60.482-1a(c) and (f), and §§60.483-1a and 60.483-2a.

- A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section, §60.482-1a(c), and §§60.483-1a and 60.483-2a.
    - Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.
    - If the existing valves in the process unit are monitored in accordance with §60.483-1a or §60.483-2a, count the new valve as leaking when calculating the percentage of valves leaking as described in §60.483-2a(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

2.41 In accordance with 40 CFR 60.482-7a(b), if an instrument reading of 500 ppm or greater is measured, a leak is detected.

2.42 In accordance with 40 CFR 60.482-7a(c), any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

- As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.
- If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

2.43 In accordance with 40 CFR 60.482-7a(d), when a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in §60.482-9a.

- A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

2.44 In accordance with 40 CFR 60.482-7a(e), first attempts at repair include, but are not limited to, the following best practices where practicable:

- Tightening of bonnet bolts;
- Replacement of bonnet bolts;
- Tightening of packing gland nuts;
- Injection of lubricant into lubricated packing.

2.45 In accordance with 40 CFR 60.482-7a(f), any valve that is designated, as described in §60.486a(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

- Has no external actuating mechanism in contact with the process fluid,
- Is operated with emissions less than 500 ppm above background as determined by the method specified in §60.485a(c), and
- Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

2.46 In accordance with 40 CFR 60.482-7a(g), any valve that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

- The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and
- The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

2.47 In accordance with 40 CFR 60.482-7a(h), any valve that is designated, as described in §60.486a(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

- The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.
- The process unit within which the valve is located either:

  - Becomes an affected facility through §60.14 or §60.15 and was constructed on or before January 5, 1981; or
  - Has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.
- The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

2.48 In accordance with 40 CFR 60.482-8a(a), if evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

- The owner or operator shall monitor the equipment within 5 days by the method specified in §60.485a(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.
- The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

2.49 In accordance with 40 CFR 60.482-8a(b), if an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

2.50 In accordance with 40 CFR 60.482-8a(c), when a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9a.

- The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

2.51 In accordance with 40 CFR 60.482-8a(d), first attempts at repair include, but are not limited to, the best practices described under §§60.482-2a(c)(2) and 60.482-7a(e).

2.52 In accordance with 40 CFR 60.482-9a(a), delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

2.53 In accordance with 40 CFR 60.482-9a(b), delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

2.54 In accordance with 40 CFR 60.482-9a(c), delay of repair for valves and connectors will be allowed if:

- The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and
- When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482-10a.

2.55 In accordance with 40 CFR 60.482-9a(d), delay of repair for pumps will be allowed if:

- Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and
- Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

2.56 In accordance with 40 CFR 60.482-9a(e), delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

2.57 In accordance with 40 CFR 60.482-9a(f), when delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

2.58 In accordance with 40 CFR 60.482-10a(a), owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

2.59 In accordance with 40 CFR 60.482-10a(b), vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent.

2.60 In accordance with 40 CFR 60.482-10a(c), enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

2.61 In accordance with 40 CFR 60.482-10a(d), flares used to comply with this subpart shall comply with the requirements of §60.18.

2.62 In accordance with 40 CFR 60.18(c)(1), flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

[October 27, 2014]

2.63 In accordance with 40 CFR 60.18(c)(2), flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).

[October 27, 2014]

2.64 In accordance with 40 CFR 60.18(c)(3), the permittee has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

- Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity, V_{max}, as determined by the following equation:

  $V_{max} = (X_{H2} - K_1) * K_2$

  Where:

  V_{max} = Maximum permitted velocity, m/sec.

  K_1 = Constant, 6.0 volume-percent hydrogen.

K_2 = Constant, 3.9(m/sec)/volume-percent hydrogen.

X_{H2} = The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in §60.17).

- The actual exit velocity of a flare shall be determined by the method specified in paragraph (f)(4) of this section.
- Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

[October 27, 2014]

2.65 In accordance with 40 CFR 60.18(c)(4), steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (c)(4) (ii) and (iii) of this section.

- Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).
- Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed.

[October 27, 2014]

2.66 In accordance with 40 CFR 60.18(c)(5), air-assisted flares shall be designed and operated with an exit velocity less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(6).

[October 27, 2014]

2.67 In accordance with 40 CFR 60.18(c)(6), flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted.

[October 27, 2014]

2.68 In accordance with 40 CFR 60.18(d), owners or operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices.

[October 27, 2014]

2.69 In accordance with 40 CFR 60.18(e), flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

[October 27, 2014]

2.70 In accordance with 40 CFR 60.18(f)(1), Method 22 of appendix A to this part shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours and shall be used according to Method 22.

[October 27, 2014]

2.71 In accordance with 40 CFR 60.18(f)(2), the presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

2.72 In accordance with 40 CFR 60.18(f)(3), the net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

Where:

H_T = Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C;

$$K = \text{Constant}, \quad 1.740 \times 10^{-7} \quad \left(\frac{1}{ppm}\right) \left(\frac{g\ mole}{scm}\right) \left(\frac{MJ}{kcal}\right)$$

where the standard temperature for $\left(\frac{g\ mole}{scm}\right)$ is 20°C;

C_i = Concentration of sample component i in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (Incorporated by reference as specified in §60.17); and

H_i = Net heat of combustion of sample component i, kcal/g mole at 25 °C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 or 88 or D4809-95 (incorporated by reference as specified in §60.17) if published values are not available or cannot be calculated.

[October 27, 2014]

2.73 In accordance with 40 CFR 60.18(f)(4), the actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.

[October 27, 2014]

2.74 In accordance with 40 CFR 60.18(f)(5), the maximum permitted velocity, V_{max}, for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation.

$\text{Log}_{10}(V_{max}) = (H_T + 28.8)/31.7$

V_{max} = Maximum permitted velocity, M/sec

28.8=Constant

31.7=Constant

H_T = The net heating value as determined in paragraph (f)(3).

[October 27, 2014]

2.75 In accordance with 40 CFR 60.18(f)(6), the maximum permitted velocity, V_{max}, for air-assisted flares shall be determined by the following equation.

$V_{max} = 8.706+0.7084 (H_T)$

V_{max} = Maximum permitted velocity, m/sec

8.706=Constant

0.7084=Constant

H_T = The net heating value as determined in paragraph (f)(3).

[October 27, 2014]

2.76 In accordance with 40 CFR 60.482-10a(e), owners or operators of control devices used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

2.77 In accordance with 40 CFR 60.482-10a(f), except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (2) of this section.

- If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements below:
    - Conduct an initial inspection according to the procedures in §60.485a(b); and
    - Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.
- If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:
    - Conduct an initial inspection according to the procedures in §60.485a(b); and
    - Conduct annual inspections according to the procedures in §60.485a(b).

2.78 In accordance with 40 CFR 60.482-10a(g), leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

- A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.
- Repair shall be completed no later than 15 calendar days after the leak is detected.

2.79 In accordance with 40 CFR 60.482-10a(h), delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

2.80 In accordance with 40 CFR 60.482-10a(i), if a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

2.81 In accordance with 40 CFR 60.482-10a(j), any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

- The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and
- The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

2.82 In accordance with 40 CFR 60.482-10a(k), any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified below:

- The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and
- The process unit within which the closed vent system is located becomes an affected facility through §§60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and
- The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

2.83 In accordance with 40 CFR 60.482-10a(l), the permittee shall record the information specified in below.

- Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.
- Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.
- For each inspection during which a leak is detected, a record of the information specified in §60.486a(c).
- For each inspection conducted in accordance with §60.485a(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.
- For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

2.84 In accordance with 40 CFR 60.482-10a(m), closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

2.85 In accordance with 40 CFR 60.482-11a(a), the permittee shall initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process

changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

2.86 In accordance with 40 CFR 60.482-11a(b), except as allowed in §60.482-1a(c), §60.482-10a, or as specified in paragraph (e) of this section, the permittee shall monitor all connectors in gas and vapor and light liquid service as specified below.

- The connectors shall be monitored to detect leaks by the method specified in §60.485a(b) and, as applicable, §60.485a(c).
- If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.
- The permittee shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.
    - If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).
    - If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.
    - If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.
        - The permittee shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.
        - If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.
        - If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

- If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.
- The permittee shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

2.87 In accordance with 40 CFR 60.482-11a(c), for use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$\%C_L = C_L / C_t * 100$

Where:

$\%C_L$ = Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

C_L = Number of connectors measured at 500 ppm or greater, by the method specified in §60.485a(b).

C_t = Total number of monitored connectors in the process unit or affected facility.

2.88 In accordance with 40 CFR 60.482-11a(d), when a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9a. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.

2.89 In accordance with 40 CFR 60.482-11a(e), any connector that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

- The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and
- The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

2.90 In accordance with 40 CFR 60.482-11a(f), inaccessible, ceramic, or ceramic-lined connectors. (1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of §§63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

- Buried;
- Insulated in a manner that prevents access to the connector by a monitor probe;
- Obstructed by equipment or piping that prevents access to the connector by a monitor probe;
- Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;

- Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or
- Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.
- If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

2.91 In accordance with 40 CFR 60.482-11a(g), except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

2.92 In accordance with 40 CFR 60.5400(b), the permittee may elect to comply with the requirements of §§60.483-1a and 60.483-2a, as an alternative.

2.93 In accordance with 40 CFR 60.483-1a(a), the permittee may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

2.94 In accordance with 40 CFR 60.483-1a(b), the following requirements shall be met if the permittee wishes to comply with an allowable percentage of valves leaking:

- An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in §60.487a(d).
- A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.
- If a valve leak is detected, it shall be repaired in accordance with §60.482-7a(d) and (e).

2.95 In accordance with 40 CFR 60.483-1a(c), performance tests shall be conducted in the following manner:

- All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in §60.485a(b).
- If an instrument reading of 500 ppm or greater is measured, a leak is detected.
- The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

2.96 In accordance with 40 CFR 60.483-1a(d), owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in §60.485a(h).

2.97 In accordance with 40 CFR 60.483-2a(a), the permittee may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

- An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in §60.487(d)a.

2.98 In accordance with 40 CFR 60.483-2a(b), the permittee shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in §60.482-7a.

- After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.
- After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.
- If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in §60.482-7a but can again elect to use this section.
- The percent of valves leaking shall be determined as described in §60.485a(h).
- The permittee must keep a record of the percent of valves found leaking during each leak detection period.
- A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with §60.482-7a(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

2.99 In accordance with 40 CFR 60.5400(c), the permittee may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of §60.5402 of this subpart.

2.100 In accordance with 40 CFR 60.5400(d), the permittee must comply with the provisions of §60.485a of this part except as provided in paragraph (f) of this section.

2.101 In accordance with 40 CFR 60.485a(a), in conducting the performance tests required in §60.8, the permittee shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

2.102 In accordance with 40 CFR 60.485a(b), the permittee shall determine compliance with the standards in §§60.482-1a through 60.482-11a, 60.483a, and 60.484a as follows:

- Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 of this part. The following calibration gases shall be used:
    - Zero air (less than 10 ppm of hydrocarbon in air); and
    - A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

- A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in §60.486a(e)(7). Calculate the average algebraic difference between the three meter readings and the most recent calibration value. Divide this algebraic difference by the initial calibration value and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

2.103 In accordance with 40 CFR 60.485a(c), the permittee shall determine compliance with the no-detectable-emission standards in §§60.482-2a(e), 60.482-3a(i), 60.482-4a, 60.482-7a(f), and 60.482-10a(e) as follows:

- The requirements of paragraph (b) shall apply.
- Method 21 of appendix A-7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

2.104 In accordance with 40 CFR 60.485a(d), the permittee shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

- Procedures that conform to the general methods in ASTM E260-73, 91, or 96, E168-67, 77, or 92, E169-63, 77, or 93 (incorporated by reference—see §60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.
- Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.
- Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

2.105 In accordance with 40 CFR 60.485a(e), the permittee shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

- The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference—see §60.17) shall be used to determine the vapor pressures.

- The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight.
- The fluid is a liquid at operating conditions.

2.106 In accordance with 40 CFR 60.485a(f), samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

2.107 In accordance with 40 CFR 60.485a(h), the permittee shall determine compliance with §60.483-1a or §60.483-2a as follows:

- The percent of valves leaking shall be determined using the following equation:

  $\%V_L = (V_L / V_T) * 100$

  Where:

  $\%V_L$ = Percent leaking valves.

  V_L = Number of valves found leaking.

  V_T = The sum of the total number of valves monitored.
- The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.
- The number of valves leaking shall include valves for which repair has been delayed.
- Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.
- If the process unit has been subdivided in accordance with §60.482-7a(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.
- The total number of valves monitored does not include a valve monitored to verify repair.

2.108 In accordance with 40 CFR 60.5400(e), the permittee must comply with the provisions of §§60.486a and 60.487a of this part except as provided in §§60.5401, 60.5421, and 60.5422 of this part.

2.109 In accordance with 40 CFR 60.486a(a), each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

- An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.
- The permittee shall record the information specified in paragraphs (a)(3)(i) through (v) of this section for each monitoring event required by §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a.
  - Monitoring instrument identification.
  - Operator identification.
  - Equipment identification.
  - Date of monitoring.
  - Instrument reading.

2.110 In accordance with 40 CFR 60.486a(b), when each leak is detected as specified in §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following requirements apply:

- A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.
- The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §60.482-7a(c) and no leak has been detected during those 2 months.
- The identification on a connector may be removed after it has been monitored as specified in §60.482-11a(b)(3)(iv) and no leak has been detected during that monitoring.
- The identification on equipment, except on a valve or connector, may be removed after it has been repaired.

2.111 In accordance with 40 CFR 60.486a(c), when each leak is detected as specified in §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

- The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.
- The date the leak was detected and the dates of each attempt to repair the leak.
- Repair methods applied in each attempt to repair the leak.
- Maximum instrument reading measured by Method 21 of appendix A-7 of this part at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.
- "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.
- The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.
- The expected date of successful repair of the leak if a leak is not repaired within 15 days.
- Dates of process unit shutdowns that occur while the equipment is unrepaired.
- The date of successful repair of the leak.

2.112 In accordance with 40 CFR 60.486a(d), the following information pertaining to the design requirements for closed vent systems and control devices described in §60.482-10a shall be recorded and kept in a readily accessible location:

- Detailed schematics, design specifications, and piping and instrumentation diagrams.
- The dates and descriptions of any changes in the design specifications.
- A description of the parameter or parameters monitored, as required in §60.482-10a(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.
- Periods when the closed vent systems and control devices required in §§60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a are not operated as designed, including periods when a flare pilot light does not have a flame.
- Dates of startups and shutdowns of the closed vent systems and control devices required in §§60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a.

2.113 In accordance with 40 CFR 60.486a(e), the following information pertaining to all equipment subject to the requirements in §§60.482-1a to 60.482-11a shall be recorded in a log that is kept in a readily accessible location:

- A list of identification numbers for equipment subject to the requirements of this subpart.
- A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§60.482-2a(e), 60.482-3a(i), and 60.482-7a(f).
    - The designation of equipment as subject to the requirements of §60.482-2a(e), §60.482-3a(i), or §60.482-7a(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.
- A list of equipment identification numbers for pressure relief devices required to comply with §60.482-4a.
- The dates of each compliance test as required in §§60.482-2a(e), 60.482-3a(i), 60.482-4a, and 60.482-7a(f).
    - The background level measured during each compliance test.
    - The maximum instrument reading measured at the equipment during each compliance test.
- A list of identification numbers for equipment in vacuum service.
- A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with §60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.
- The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.
- Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A-7 of this part and §60.485a(b).
    - Date of calibration and initials of operator performing the calibration.
    - Calibration gas cylinder identification, certification date, and certified concentration.
    - Instrument scale(s) used.
    - A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A-7 of this part.
    - Results of each calibration drift assessment required by §60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).
    - If an owner or operator makes their own calibration gas, a description of the procedure used.
- The connector monitoring schedule for each process unit as specified in §60.482-11a(b)(3)(v).
- Records of each release from a pressure relief device subject to §60.482-4a.

2.114 In accordance with 40 CFR 60.486a(f), the following information pertaining to all valves subject to the requirements of §60.482-7a(g) and (h), all pumps subject to the requirements of §60.482-2a(g), and all connectors subject to the requirements of §60.482-11a(e) shall be recorded in a log that is kept in a readily accessible location:

- A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.
- A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

2.115 In accordance with 40 CFR 60.486a(g), the following information shall be recorded for valves complying with §60.483-2a:

- A schedule of monitoring.
- The percent of valves found leaking during each monitoring period.

2.116 In accordance with 40 CFR 60.486a(h), the following information shall be recorded in a log that is kept in a readily accessible location:

- Design criterion required in §§60.482-2a(d)(5) and 60.482-3a(e)(2) and explanation of the design criterion; and
- Any changes to this criterion and the reasons for the changes.

2.117 In accordance with 40 CFR 60.486a(i), the following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in §60.480a(d):

- An analysis demonstrating the design capacity of the affected facility,
- A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and
- An analysis demonstrating that equipment is not in VOC service.

2.118 In accordance with 40 CFR 60.486a(j), information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

2.119 In accordance with 40 CFR 60.486a(k), the provisions of §60.7(b) and (d) do not apply to affected facilities subject to this subpart.

2.120 In accordance with 40 CFR 60.487a(a), each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.

2.121 In accordance with 40 CFR 60.487a(b), the initial semiannual report to the Administrator shall include the following information:

- Process unit identification.
- Number of valves subject to the requirements of §60.482-7a, excluding those valves designated for no detectable emissions under the provisions of §60.482-7a(f).
- Number of pumps subject to the requirements of §60.482-2a, excluding those pumps designated for no detectable emissions under the provisions of §60.482-2a(e) and those pumps complying with §60.482-2a(f).

- Number of compressors subject to the requirements of §60.482-3a, excluding those compressors designated for no detectable emissions under the provisions of §60.482-3a(i) and those compressors complying with §60.482-3a(h).
- Number of connectors subject to the requirements of §60.482-11a.

2.122 In accordance with 40 CFR 60.487a(c), all semiannual reports to the Administrator shall include the following information, summarized from the information in §60.486a:

- Process unit identification.
- For each month during the semiannual reporting period,
    - Number of valves for which leaks were detected as described in §60.482-7a(b) or §60.483-2a,
    - Number of valves for which leaks were not repaired as required in §60.482-7a(d)(1),
    - Number of pumps for which leaks were detected as described in §60.482-2a(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),
    - Number of compressors for which leaks were detected as described in §60.482-3a(f),
    - Number of compressors for which leaks were not repaired as required in §60.482-3a(g)(1),
    - Number of connectors for which leaks were detected as described in §60.482-11a(b),
    - Number of connectors for which leaks were not repaired as required in §60.482-11a(d), and
    - The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.
- Dates of process unit shutdowns which occurred within the semiannual reporting period.
- Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

2.123 In accordance with 40 CFR 60.487a(d), the permittee electing to comply with the provisions of §§60.483-1a or 60.483-2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

2.124 In accordance with 40 CFR 60.487a(e), the permittee shall report the results of all performance tests in accordance with §60.8 of the General Provisions. The provisions of §60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

2.125 In accordance with 40 CFR 60.487a(f), the requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the state.

2.126 In accordance with 40 CFR 60.5400(f), the permittee must use the following provision instead of §60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in §60.17) must be used.

2.127 In accordance with 40 CFR 60.5401(a), the permittee may comply with the following exceptions to the provisions of §60.5400(a) and (b).

2.128 In accordance with 40 CFR 60.5401(b), each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b) except as provided in §60.5400(c) and in paragraph (b)(4) of this section, and §60.482-4a(a) through (c) of subpart VVa.

- If an instrument reading of 500 ppm or greater is measured, a leak is detected.
- When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.
    - A first attempt at repair must be made no later than 5 calendar days after each leak is detected.
- Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1) of subpart VVa.
    - No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

2.129 In accordance with 40 CFR 60.5401(c), sampling connection systems are exempt from the requirements of §60.482-5a.

2.130 In accordance with 40 CFR 60.5401(d), pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§60.482-2a(a)(1) and 60.482-7a(a), and paragraph (b)(1) of this section.

2.131 In accordance with 40 CFR 60.5401(f), the permittee may use the following provisions instead of §60.485a(e):

- Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).
- Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302 °F) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

2.132 In accordance with 40 CFR 60.5401(g), the permittee may use the following provisions instead of §60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in §60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

2.133 In accordance with 40 CFR 60.5402(a), if, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

2.134 In accordance with 40 CFR 60.5402(b), any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

2.135 In accordance with 40 CFR 60.5402(c), the Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

2.136 In accordance with 40 CFR 60.5402(d), the Administrator will treat applications under this section according to the following criteria, except in cases where the Administrator concludes that other criteria are appropriate:

- The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.
- If the applicant is an owner or operator of an affected facility, the applicant must commit in writing to operate and maintain the alternative means so as to achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard.

2.137 In accordance with 40 CFR 60.5410, the permittee must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (i) of this section. The initial compliance period begins on October 15, 2012, or upon initial startup, whichever is later, and ends no later than one year after the initial startup date for the permittee's affected facility or no later than one year after October 15, 2012. The initial compliance period may be less than one full year.

2.138 In accordance with 40 CFR 60.5410(a), to achieve initial compliance with the standards for each well completion operation conducted at the gas well affected facility the permittee must comply with paragraphs below.

- The permittee must submit the notification required in §60.5420(a)(2).

- The permittee must submit the initial annual report for the well affected facility as required in §60.5420(b).
- The permittee must maintain a log of records as specified in §60.5420(c)(1)(i) through (iv) for each well completion operation conducted during the initial compliance period.
- For each gas well affected facility subject to both §60.5375(a)(1) and (3), as an alternative to retaining the records specified in §60.5420(c)(1)(i) through (iv), the permittee may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each gas well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

2.139 In accordance with 40 CFR 60.5410(d), to achieve initial compliance with emission standards for the permittee's pneumatic controller affected facility the permittee must comply with the requirements specified below.

- The permittee must demonstrate initial compliance by maintaining records as specified in §60.5420(c)(4)(ii) of the permittee's determination that the use of a pneumatic controller affected facility with a bleed rate greater than 6 standard cubic feet of gas per hour is required as specified in §60.5390(a).
- The permittee own or operate a pneumatic controller affected facility located at a natural gas processing plant and the permittee's pneumatic controller is driven by a gas other than natural gas and therefore emits zero natural gas.
- The permittee own or operate a pneumatic controller affected facility located between the wellhead and a natural gas processing plant and the manufacturer's design specifications indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.
- The permittee must tag each new pneumatic controller affected facility according to the requirements of §60.5390(b)(2) or (c)(2).
- The permittee must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for the permittee's pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of §60.5420(b).
- The permittee must maintain the records as specified in §60.5420(c)(4) for each pneumatic controller affected facility.

2.140 In accordance with 40 CFR 60.5410(f), for affected facilities at onshore natural gas processing plants, initial compliance with the VOC requirements is demonstrated if the permittee is in compliance with the requirements of §60.5400.

2.141 In accordance with 40 CFR 60.5415(a), for each gas well affected facility, the permittee must demonstrate continuous compliance by submitting the reports required by §60.5420(b) and maintaining the records for each completion operation specified in §60.5420(c)(1).

2.142 In accordance with 40 CFR 60.5415(d), for each pneumatic controller affected facility, the permittee must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

- The permittee must continuously operate the pneumatic controllers as required in §60.5390(a), (b), or (c).
- The permittee must submit the annual report as required in §60.5420(b).
- The permittee must maintain records as required in §60.5420(c)(4).

2.143 In accordance with 40 CFR 60.5415(f), for affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if the permittee is in compliance with the requirements of §60.5400.

2.144 In accordance with 40 CFR 60.5415(h), affirmative defense for violations of emission standards during malfunction. In response to an action to enforce the standards set forth in §§60.5375, 60.5380, 60.5385, 60.5390, 60.5395, 60.5400, and 60.5405, the permittee may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at §60.2. Appropriate penalties may be assessed, however, if the permittee fails to meet the burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

- To establish the affirmative defense in any action to enforce such a standard, the permittee must timely meet the reporting requirements in §60.5415(h)(2), and must prove by a preponderance of evidence that:
    - The violation:
        - Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and
        - Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and
        - Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and
        - Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and
    - Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and
    - The frequency, amount and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and
    - If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
    - All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment and human health; and
    - All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

- All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and
- At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and
- A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

- Report. The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (h)(1) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

2.145 In accordance with 40 CFR 60.5420(a), the permittee must submit the notifications according to paragraphs (a)(1) and (2) of this section if the permittee owns or operates one or more of the affected facilities specified in §60.5365 that was constructed, modified, or reconstructed during the reporting period.

- If the permittee owns or operates a gas well, pneumatic controller, centrifugal compressor, reciprocating compressor or storage vessel affected facility the permittee is not required to submit the notifications required in §60.7(a)(1), (3), and (4).
- If the permittee owns or operates a gas well affected facility, the permittee must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the API well number, the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. The permittee may submit the notification in writing or in electronic format.
    - If the permittee is subject to state regulations that require advance notification of well completions and the permittee has met those notification requirements, then the permittee is considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

2.146 In accordance with 40 CFR 60.5420(b), the permittee must submit annual reports containing the information specified below to the Administrator and performance test reports as specified below. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to §60.5410. Subsequent annual reports are due no later than same date each year as the initial annual report. If the permittee owns or operates more than one affected facility, the permittee may submit one report for multiple affected facilities provided the report contains all of the information required as specified below. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. The permittee

may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

- The general information specified below.
    - The company name and address of the affected facility.
    - An identification of each affected facility being included in the annual report.
    - Beginning and ending dates of the reporting period.
    - 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.
- For each gas well affected facility, the information below.
    - Records of each well completion operation as specified in paragraph (c)(1)(i) through (iv) of this section for each gas well affected facility conducted during the reporting period. In lieu of submitting the records specified in paragraph (c)(1)(i) through (iv), the owner or operator may submit a list of the well completions with hydraulic fracturing completed during the reporting period and the records required by paragraph (c)(1)(v) of this section for each well completion.
    - Records of deviations specified in paragraph (c)(1)(ii) of this section that occurred during the reporting period.
- For each pneumatic controller affected facility, the information specified below.
    - An identification of each pneumatic controller constructed, modified or reconstructed during the reporting period, including the identification information specified in §60.5390(b)(2) or (c)(2).
    - If applicable, documentation that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.
    - Records of deviations specified in paragraph (c)(4)(v) of this section that occurred during the reporting period.
- Within 60 days after the date of completing each performance test (see §60.8 of this part) as required by this subpart, except testing conducted by the manufacturer as specified in §60.5413(d), the permittee must submit the results of the performance tests required by this subpart to the EPA as follows. The permittee must use the latest version of the EPA's Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/index.html) existing at the time of the performance test to generate a submission package file, which documents the performance test. The permittee must then submit the file generated by the ERT through the EPA's Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed by logging in to the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/). Only data collected using test methods supported by the ERT as listed on the ERT Web site are subject to this requirement for submitting reports electronically. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02,

4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, the permittee must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test to the Administrator at the appropriate address listed in §60.4.

- For enclosed combustors tested by the manufacturer in accordance with §60.5413(d), an electronic copy of the performance test results required by §60.5413(d) shall be submitted via email to Oil_and_Gas_PT@EPA.GOV unless the test results for that model of combustion control device are posted at the following Web site: epa.gov/airquality/oilandgas/.

2.147 In accordance with 40 CFR 60.5420(c), the permittee must maintain the records identified as specified in §60.7(f) and as identified below. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years.

- The records for each gas well affected facility as specified below.
    - Records identifying each well completion operation for each gas well affected facility;
    - Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in §60.5375.
    - Records required in §60.5375(b) or (f) for each well completion operation conducted for each gas well affected facility that occurred during the reporting period. The permittee must maintain the records specified in paragraphs below.
        - For each gas well affected facility required to comply with the requirements of §60.5375(a), the permittee must record: The location of the well; the API well number; the duration of flowback; duration of recovery to the flow line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours of time.
        - For each gas well affected facility required to comply with the requirements of §60.5375(f), the permittee must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that the permittee does not have to record the duration of recovery to the flow line.
    - For each gas well facility for which the permittee claims an exception under §60.5375(a)(3), the permittee must record: The location of the well; the API well number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

- For each gas well affected facility required to comply with both §60.5375(a)(1) and (3), if the permittee is using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, the permittee must retain the records of the digital photograph as specified in §60.5410(a)(4).

- For each pneumatic controller affected facility, the permittee must maintain the records identified below.
  - Records of the date, location and manufacturer specifications for each pneumatic controller constructed, modified or reconstructed.
  - Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.
  - If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.
  - If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.
  - Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in §60.5390.

2.148 In accordance with 40 CFR 60.5421(b), the following recordkeeping requirements apply to pressure relief devices subject to the requirements of §60.5401(b)(1) of this subpart.

- When each leak is detected as specified in §60.5401(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.
- When each leak is detected as specified in §60.5401(b)(2), the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:
  - The instrument and operator identification numbers and the equipment identification number.
  - The date the leak was detected and the dates of each attempt to repair the leak.
  - Repair methods applied in each attempt to repair the leak.
  - "Above 500 ppm" if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.
  - "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.
  - The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.
  - The expected date of successful repair of the leak if a leak is not repaired within 15 days.
  - Dates of process unit shutdowns that occur while the equipment is unrepaired.
  - The date of successful repair of the leak.

- A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) must be signed by the owner or operator.

2.149 In accordance with 40 CFR 60.5422(b), the permittee must include the following information in the initial semiannual report in addition to the information required in §60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of §60.5401(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c).

2.150 In accordance with 40 CFR 60.5422(c), the permittee must include the following information in all semiannual reports in addition to the information required in §60.487a(c)(2)(i) through (vi):

- Number of pressure relief devices for which leaks were detected as required in §60.5401(b)(2); and
- Number of pressure relief devices for which leaks were not repaired as required in §60.5401(b)(3).

2.151 NSPS 40 CFR 60 – General Provisions

The permittee shall comply with the requirements of 40 CFR 60, Subpart A – General Provisions. A summary of applicable requirements for affected facilities is provided in the following table:

Table 2.2 Subpart A – General Provisions

Citation	Subject	Explanation
40 CFR 60.1	General Applicability of the General Provisions	
40 CFR 60.2	Definitions	Additional terms defined in §60.5430.
40 CFR 60.3	Units and abbreviations	
40 CFR 60.4	Address	
40 CFR 60.5	Determination of construction or modification	
40 CFR 60.6	Review of Plans	
40 CFR 60.7	Notification and record keeping	Except that §60.7 only applies as specified in §60.5420(a).
40 CFR 60.8	Performance tests	Performance testing is required for control devices used on storage vessels and centrifugal compressors.
40 CFR 60.9	Availability of information	
40 CFR 60.10	State authority	
40 CFR 60.12	Circumvention	
40 CFR 60.13	Monitoring requirements	Continuous monitors are required for storage vessels.
40 CFR 60.14	Modification	
40 CFR 60.15	Reconstruction	
40 CFR 60.16	Priority list	
40 CFR 60.17	Incorporations by reference	
40 CFR 60.18	General control device requirements	Except that §60.18 does not apply to flares.
40 CFR 60.19	General notification and reporting requirement	

2.152 Incorporation by Reference

Unless expressly provided otherwise, any reference in this permit to any document identified in IDAPA 58.01.01.107.03 shall constitute the full incorporation into this permit of that document for the purposes of the reference, including any notes and appendices therein. Documents include, but are not limited to:

- Standards of Performance for New Stationary Sources (NSPS), 40 CFR Part 60, Subpart OOOO and OOOOa

For permit conditions referencing or cited in accordance with any document incorporated by reference (including permit conditions identified as NSPS or NESHAP), should there be any conflict between the requirements of the permit condition and the requirements of the document, the requirements of the document shall govern, including any amendments to that regulation.

[October 27, 2017]

3 Compressor Engines

3.1 Process Description

Natural gas is compressed at the NWGP Highway 30 Treating Facility prior to delivery to the Northwest Pipeline. The compressors are driven by four Caterpillar natural gas-fired richburn IC engines. The existing engine (Compressor Engine 1) was manufactured in 1990 and is subject to 40 CFR 63, Subpart ZZZZ. The three additional engines manufacture date have not been determined and are subject to 40 CFR 63, Subpart ZZZZ and/or 40 CFR 60, Subpart JJJJ if the engines are manufactured after June 12, 2006. All potentially applicable requirements are included below.

[October 27, 2017]

3.2 Control Device Descriptions

Table 3.1 Compressor Engines Description

Emissions Units / Processes	Control Devices
Compressor Engine 1	NSCR
Compressor Engine 2	NSCR may be utilized as required to meet the requirements of 40 CFR 63 Subpart ZZZZ
Compressor Engine 3	NSCR may be utilized as required to meet the requirements of 40 CFR 63 Subpart ZZZZ
Compressor Engine 4	None

[October 27, 2017]

Emission Limits

3.3 Emission Limit

The permittee shall not discharge to the atmosphere from any fuel burning equipment with a maximum rated input of ten million BTU per hour or more, PM in excess of 0.015 gr/dscf corrected to 3% oxygen, in accordance with IDAPA 58.01.01.676-677.

[October 27, 2014]

3.4 Opacity Limit

Emissions from the Compressor Engines stack, or any other stack, vent, or functionally equivalent opening associated with the compressor engines, shall not exceed 20% opacity for a period or periods aggregating more than three minutes in any 60-minute period as required by IDAPA 58.01.01.625. Opacity shall be determined by the procedures contained in IDAPA 58.01.01.625.

[October 27, 2017]

Operating Requirements

3.5 Fuel Type Restriction

Compressor Engines 1 through 4 shall be fired on natural gas exclusively.

[October 27, 2017]

Monitoring and Recordkeeping Requirements

3.6 Opacity Monitoring

The permittee shall conduct a quarterly facility-wide inspection of potential sources of visible emissions, during daylight hours and under normal operating conditions. The inspection shall consist of a see/no see evaluation for each potential source of visible emissions. If any visible emissions are present from any point of emission, the permittee shall either

a) take appropriate corrective action as expeditiously as practicable to eliminate the visible emissions. Within 24 hours of the initial see/no see evaluation and after the corrective action, the permittee shall conduct a see/no see evaluation of the emissions point in question. If the visible emissions are not eliminated, the permittee shall comply with b).

or

b) perform a Method 9 opacity test in accordance with the procedures outlined in IDAPA 58.01.01.625. A minimum of 30 observations shall be recorded when conducting the opacity test. If opacity is greater than 20%, as measured using Method 9, for a period or periods aggregating more than three minutes in any 60-minute period, the permittee shall take all necessary corrective action and report the exceedance in accordance with IDAPA 58.01.01.130-136.

The permittee shall maintain records of the results of each visible emission inspection and each opacity test when conducted. The records shall include, at a minimum, the date and results of each inspection and test and a description of the following: the permittee's assessment of the conditions existing at the time visible emissions are present (if observed), any corrective action taken in response to the visible emissions, and the date corrective action was taken.

Federal Requirements

40 CFR 63 Subpart ZZZZ Requirements

"National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines"

3.7 In accordance with 40 CFR 63.6595(a)(1), the permittee must comply with the applicable emission and operating limitations of the National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ by October 19, 2013 or upon installation.

3.8 In accordance with 40 CFR 63.6603, the permittee shall comply with the requirements in Table 2d to install NSCR (non-selective catalytic reduction) to reduce HAP emissions on Compressor Engines 1, 2, and 3. The permittee shall comply with the following requirements in Table 2d for Compressor Engine 4:

- Change oil and filter every 1,440 hours of operation or annually, whichever comes first;
- Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and replace as necessary
- Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first; and replace as necessary.

[October 27, 2017]

3.9 In accordance with 40 CFR 63.6605, the permittee shall, at all times, operate and maintain the Compressor Engines, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the permittee to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[October 27, 2017]

3.10 In accordance with 40 CFR 63.6612, the permittee shall conduct any initial performance test or other initial compliance demonstration according to Table 5 to this subpart. In order to comply with the requirement to reduce CO and THC emissions, the permittee shall:

- Install NSCR
- Conduct an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more
- Install a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or install equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

3.11 In accordance with 40 CFR 63.6625(e), the permittee shall operate and maintain Compressor Engine 4 according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

[October 27, 2017]

3.12 In accordance with 40 CFR 63.6625(h), the permittee shall minimize each compressor engines' time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes.

[October 27, 2017]

3.13 In accordance with 40 CFR 63.6625(j), the permittee has the option of utilizing an oil analysis program in order to extend the specified oil change requirements for Compressor Engine 4. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2d to the Subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later.

The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[October 27, 2017]

3.14 In accordance with 40 CFR 63.6630(e), the permittee shall meet the following requirements to demonstrate initial compliance:

- The compliance demonstration must consist of at least three test runs.
- Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.
- To demonstrate compliance with the CO concentration or CO percent reduction requirement, the permittee must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.
- To demonstrate compliance with the THC percent reduction requirement, the permittee must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.
- The permittee must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.
- To demonstrate compliance with the CO or THC percent reduction requirement, the permittee must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

3.15 In accordance with 40 CFR 63.6635(a), the permittee must monitor and collect data for Compressor Engines 1, 2, and 3.

[October 27, 2017]

3.16 In accordance with 40 CFR 63.6635(b), the permittee must monitor continuously at all times that Compressor Engines 1, 2, and 3 are operating except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

[October 27, 2017]

3.17 In accordance with 40 CFR 63.6635(c), the permittee may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. The permittee must, however, use all the valid data collected during all other periods.

3.18 In accordance with 40 CFR 63.6640(c), the annual compliance demonstration required shall be conducted according to the following requirements:

- The compliance demonstration must consist of at least one test run.
- Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.
- To demonstrate compliance with the CO concentration or CO percent reduction requirement, the permittee must measure CO emissions using one of the CO

measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

- To demonstrate compliance with the THC percent reduction requirement, the permittee must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.
- The permittee must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.
- To demonstrate compliance with the CO or THC percent reduction requirement, the permittee must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.
- If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the permittee demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

3.19 In accordance with 40 CFR 63.6645(a), the permittee shall submit all of the notifications in §§63.7(b) and (c) that apply by the dates specified for the Compressor Engines.

[October 27, 2017]

3.20 In accordance with 40 CFR 63.6645(g), the permittee shall submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1) for Compressor Engines 1, 2, and 3.

[October 27, 2017]

3.21 In accordance with 40 CFR 63.6645(h), the permittee shall submit a Notification of Compliance Status according to §63.9(h)(2)(ii) for Compressor Engines 1, 2, and 3.

- The permittee shall submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

[October 27, 2017]

3.22 In accordance with 40 CFR 63.6650(b), the permittee shall, for semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for the affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for the source in §63.6595.

- The permittee shall ensure, for semiannual Compliance reports, that the first Compliance report be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date.
- The permittee shall ensure, for semiannual Compliance reports, each subsequent Compliance report cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

- The permittee shall ensure, for semiannual Compliance reports, each subsequent Compliance report be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

3.23 In accordance with 40 CFR 63.6650(c), the permittee's Compliance report must contain the following:

- Company name and address.
- Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.
- Date of report and beginning and ending dates of the reporting period.
- If a malfunction occurred during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by the permittee during a malfunction to minimize emissions including actions taken to correct a malfunction.
- If there are no deviations from any emission or operating limitations that apply, a statement that there were no deviations from the emission or operating limitations during the reporting period.

3.24 In accordance with 40 CFR 63.6655(a), the permittee shall keep the following records:

- A copy of each notification and report that is submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that is submitted.
- Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.
- Records of performance tests and performance evaluations.
- Records of all required maintenance performed on the air pollution control and monitoring equipment.
- Records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

3.25 In accordance with 40 CFR 63.6655(d), the permittee shall keep the records required in Table 6 to this subpart to show compliance with each emission or operating limitation for Compressor Engines 1, 2, and 3.

[October 27, 2017]

3.26 In accordance with 40 CFR 63.6655 (e), the permittee shall keep the records of the maintenance conducted on the stationary RICE, in order to demonstrate that the permittee operated and maintained the stationary RICE and after-treatment control device (if any) according to the permittee's own maintenance plan.

[October 27, 2017]

3.27 In accordance with 40 CFR 63.6660(a), the permittee shall keep the records in a form suitable and readily available for expeditious review according to 40 CFR 63.10(b)(1).

3.28 In accordance with 40 CFR 63.6660(b), the permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

3.29 In accordance with 40 CFR 63.6660(c), the permittee shall keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1).

3.30 NESHAPS 40 CFR 63 – General Provisions

The permittee shall comply with the requirements of 40 CFR 63, Subpart A – General Provisions. A summary of applicable requirements for affected facilities is provided in the following table:

Table 3.3 Subpart A – General Provisions

Citation	Subject	Explanation
40 CFR 63.1(a)(1)-(12)	General Applicability	
40 CFR 63.1(b)(1)-(3)	Initial Applicability Determination	Applicability of subpart ZZZZ is also specified in 40 CFR 63.6585
40 CFR 63.1(c)(1)	Applicability After Standard Established	
40 CFR 63.1(c)(2)	Applicability of Permit Program for Area Sources	
40 CFR 63.1(c)(5)	Notifications	
40 CFR 63.2	Definitions	Additional definitions are specified in 40 CFR 63.6675.
40 CFR 63.3(a)–(c)	Units and Abbreviations	
40 CFR 63.4(a)(1)–(5)	Prohibited Activities	
40 CFR 63.4(b)–(c)	Circumvention/Fragmentation	
40 CFR 63.6(a)	Compliance With Standards and Maintenance Requirements—Applicability	
40 CFR 63.6(b)(1)-(7)	Compliance Dates for New and Reconstructed Sources	40 CFR 63.6595 specifies the compliance dates.
40 CFR 63.6(c)(1)-(5)	Compliance Dates for Existing Sources	40 CFR 63.6595 specifies the compliance dates.
40 CFR 63.6(f)(2)-(3)	Methods for Determining Compliance	
40 CFR 63.6(g)(1)-(3)	Use of an Alternative Standard	
40 CFR 63.6(i)(1)-(16)	Extension of Compliance	
40 CFR 63.6(j)	Presidential Compliance Exemption	
40 CFR 63.7(a)(1)-(2)	Performance Test Dates	40 CFR 63.6610-6612 specify the performance test dates
40 CFR 63.7(b)(1)-(2)	Notification of Performance Test and Rescheduling	40 CFR 63.6645 specifies the notification
40 CFR 63.7(e)(2)	Conduct Performance Test and reduction of data	40 CFR 63.6620 specifies appropriate test methods
40 CFR 63.7(g)	Performance Test data analysis and recordkeeping and reporting	
40 CFR 63.8	Monitoring Requirements	40 CFR 63.6625 specifies appropriate monitoring requirements
40 CFR 63.9(a)-(e), (g)-(j)	Notification Requirements	40 CFR 63.645 specifies notification requirements.
40 CFR 63.10(a)	Recordkeeping/Reporting—Applicability and General Information	
40 CFR 63.10(b)(1)	General Recordkeeping Requirements	Additional requirements are specified in 40 CFR 63.6655
40 CFR 63.10(b)(2)(xii)	Waiver of recordkeeping requirements	
40 CFR 63.10(b)(2)(xiv)	Records supporting notifications	
40 CFR 63.10(b)(3)	Recordkeeping Requirements for Applicability Determinations	
40 CFR 63.10(d)(1)	General Reporting Requirements	Additional requirements are specified in 40 CFR 63.6650
40 CFR 63.10(d)(4)	Progress Reports for Sources With Compliance Extensions	
40 CFR 63.10(f)	Recordkeeping/Reporting Waiver	
40 CFR 63.12	State Authority and Delegations	
40 CFR 63.13	Addresses of State Air Pollution Control Agencies and EPA Regional Offices	

Citation	Subject	Explanation
40 CFR 63.14	Incorporation by Reference	
40 CFR 63.15	Availability of Information/Confidentiality	

40 CFR 60 Subpart JJJJ Requirements

"Standards of Performance for Stationary Spark Ignition Internal Combustion Engines"

3.31 In accordance with 40 CFR 60.4233, the permittee must comply with the emission standards in Table 1 to this subpart.

Table 3.4 Table 1 to Subpart JJJJ of Part 60 – NO_x, CO and VOC Emission Standards for Stationary Non-Emergency SI Gas Engines ≥100 HP

Engine type and fuel	Maximum engine power	Manufacture date	Emission Standards [a]					
			g/hp-hr			ppmvd at 15% O_2		
			NO_X	CO	VOC [b]	NO_X	CO	VOC [b]
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG	100≤hp<500	7/1/2008	2.0	4.0	1.0	160	540	86
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG (except lean burn 500≤HP<1,350)	hp≥500	7/1/2007	2.0	4.0	1.0	160	540	86
	hp≥500	7/1/2010	1.0	2.0	0.7	82	270	60

a) Owners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/hp-hr or ppmvd at 15 percent O_2.

b) For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

[October 27, 2017]

3.32 In accordance with 40 CFR 60.4234, the permittee shall operate and maintain stationary SI ICE that achieve the emission standards as required in 40 CFR 60.4233(e) over the entire life of the engine.

[October 27, 2017]

3.33 In accordance with 40 CFR 60.4243(b)(1), if the permittee chooses to purchase a certified engine, the permittee shall purchase an engine certified according to procedures specified in the subpart for the same model year demonstrating compliance to one of the methods specified in paragraph (a) of the section.

[October 27, 2017]

3.34 In accordance with 40 CFR 60.4243(b)(2)(i), if the permittee chooses to purchase a non-certified engine greater than 25 hp and less than or equal to 500 hp, the permittee must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance.

[October 27, 2017]

3.35 In accordance with 40 CFR 60.4243(b)(2)(ii), if the permittee chooses to purchase a non-certified engine greater than 500 hp, the permittee shall keep a maintenance plan and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition the permittee must conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

[October 27, 2017]

3.36 In accordance with 40 CFR 60.4243(e), the permittee may operate their engines using propane for a maximum of 100 hours per year as an alternative fuel solely during emergency operations, but must keep records of such use. If propane is used for more than 100 hours per year in an engine that is not certified to the emission standards when using propane, the owners and operators are required to conduct a performance test to demonstrate compliance with the emission standards of §60.4233.

[October 27, 2017]

3.37 In accordance with 40 CFR 60.4243(f), if the permittee operates a stationary SI internal combustion engine that is less than or equal to 500 HP and purchase a non-certified engine or do not operate and maintain your certified stationary SI internal combustion engine and control device according to the manufacturer's written emission-related instructions, the permittee is required to perform initial performance testing as indicated in this section, but are not required to conduct subsequent performance testing unless the stationary engine is rebuilt or undergoes major repair or maintenance. A rebuilt stationary SI ICE means an engine that has been rebuilt as that term is defined in 40 CFR 94.11(a).

[October 27, 2017]

3.38 In accordance with 40 CFR 60.4244(a), each performance test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and according to the requirements in §60.8 and under the specific conditions that are specified by Table 2 to this Subpart.

Table 3.5 Table 2 to Subpart JJJJ of Part 60—Requirements for Performance Tests

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary SI internal combustion engine demonstrating compliance according to §60.4244.	a. limit the concentration of NO_x in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)[a].	(a) If using a control device, the sampling site must be located at the outlet of the control device.
	ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)[a].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_x concentration.	
	iii. Determine the exhaust flow rate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60.		

For each	Complying with the requirement to	You must	Using	According to the following requirements
	iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for NO_x concentration.	
	v. Measure NO_x at the exhaust of the stationary internal combustion engine.	(5) Method 7E of 40 CFR part 60, appendix A, Method D6522–00(2005)[a], Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(d) Results of this test consist of the average of the three 1-hour or longer runs.	
	b. limit the concentration of CO in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A.	(a) If using a control device, the sampling site must be located at the outlet of the control device.
	ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)[a].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for CO concentration.	
	iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for CO concentration.	
	v. Measure CO at the exhaust of the stationary internal combustion engine.	(5) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00(2005)[a], Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17).	(d) Results of this test consist of the average of the three 1-hour or longer runs.	
	c. limit the concentration of VOC in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A.	(a) If using a control device, the sampling site must be located at the outlet of the control device.
	ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)[a].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for	

For each	Complying with the requirement to	You must	Using	According to the following requirements
	port location;		VOC concentration.	
	iii. Determine the exhaust flow rate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60.		
	iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for VOC concentration.	
	v. Measure VOC at the exhaust of the stationary internal combustion engine.	(5) Methods 25A and 18 of 40 CFR part 60, appendix A, Method 25A with the use of a methane cutter as described in 40 CFR 1065.265, Method 18 or 40 CFR part 60, appendix A,[c,d] Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(d) Results of this test consist of the average of the three 1-hour or longer runs.	

a) ASTM D6522–00 is incorporated by reference; see 40 CFR 60.17. Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

b) You may use ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses, for measuring the O_2 content of the exhaust gas as an alternative to EPA Method 3B.

c) You may use EPA Method 18 of 40 CFR part 60, appendix A, provided that you conduct an adequate presurvey test prior to the emissions test, such as the one described in OTM 11 on EPA's Web site (http://www.epa.gov/ttn/emc/prelim/otm11.pdf).

d) You may use ASTM D6420–99 (2004), Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry as an alternative to EPA Method 18 for measuring total nonmethane organic.

[October 27, 2017]

3.39 In accordance with 40 CFR 60.4244(b), the permittee may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c). If the stationary SI internal combustion engine is non-operational, the permittee does not need to startup the engine solely to conduct a performance test; however, the permittee must conduct the performance test immediately upon startup of the engine.

[October 27, 2017]

3.40 In accordance with 40 CFR 60.4244(c), the permittee must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.

[October 27, 2017]

3.41 In accordance with 40 CFR 60.4244(d), to determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 1:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{HP - hr} \qquad \text{(Eq. 1)}$$

Where:

ER = Emission rate of NOX in g/HP-hr.

Cd = Measured NOX concentration in parts per million by volume (ppmv).

1.912×10−3 = Conversion constant for ppm NOX to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, horsepower-hour (HP-hr).

[October 27, 2017]

3.42 In accordance with 40 CFR 60.4244(e), to determine compliance with the CO mass per unit output emission limitation, convert the concentration of CO in the engine exhaust using Equation 2:

$$ER = \frac{C_d \times 1.164 \times 10^{-3} \times Q \times T}{HP - hr} \quad \text{(Eq. 2)}$$

Where:

ER = Emission rate of CO in g/HP-hr.

Cd = Measured CO concentration in ppmv.

1.164×10−3 = Conversion constant for ppm CO to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

[October 27, 2017]

3.43 In accordance with 40 CFR 60.4244(f), when calculating emissions of VOC, emissions of formaldehyde should not be included. To determine compliance with the VOC mass per unit output emission limitation, convert the concentration of VOC in the engine exhaust using Equation 3:

$$ER = \frac{C_d \times 1.833 \times 10^{-3} \times Q \times T}{HP - hr} \quad \text{(Eq. 3)}$$

Where:

ER = Emission rate of VOC in g/HP-hr.

Cd = VOC concentration measured as propane in ppmv.

1.833×10−3 = Conversion constant for ppm VOC measured as propane, to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

[October 27, 2017]

3.44 In accordance with 40 CFR 60.4244(g), if the permittee chooses to measure VOC emissions using either Method 18 of 40 CFR part 60, appendix A, or Method 320 of 40 CFR part 63, appendix A, then it has the option of correcting the measured VOC emissions to account for the potential differences in measured values between these methods and Method 25A. The results from Method 18 and Method 320 can be corrected for response factor differences using Equations 4 and 5 of this section.

The corrected VOC concentration can then be placed on a propane basis using Equation 6 of this section.

$$RF_i = \frac{C_{Mi}}{C_{Ai}} \quad \text{(Eq. 4)}$$

Where:

RFi = Response factor of compound i when measured with EPA Method 25A.

CMi = Measured concentration of compound i in ppmv as carbon.

CAi = True concentration of compound i in ppmv as carbon.

$$C_{icorr} = RF_i \times C_{imeas} \quad \text{(Eq. 5)}$$

Where:

Cicorr = Concentration of compound i corrected to the value that would have been measured by EPA Method 25A, ppmv as carbon.

Cimeas = Concentration of compound i measured by EPA Method 320, ppmv as carbon.

$$C_{Peq} = 0.6098 \times C_{icorr} \quad \text{(Eq. 6)}$$

Where:

CPeq = Concentration of compound i in mg of propane equivalent per DSCM.

[October 27, 2017]

3.45 In accordance with 40 CFR 60.4245(a)(1) and (2), the permittee shall keep records of the following information:

- For each engine notifications submitted and all documentation supporting any notification.
- Maintenance conducted on each SI engine.
- If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to §60.4243(a)(2), documentation that the engine meets the emission standards.

The permittee shall maintain these records on-site and be made available to DEQ representatives upon request for a period of at least five years.

[October 27, 2017]

3.46 In accordance with 40 CFR 60.4245(c), owners and operators of stationary SI ICE greater than or equal to 500 HP that have not been certified by an engine manufacturer to meet the emission standards in §60.4231 must submit an initial notification as required in §60.7(a)(1). The notification must include the following information.

- Name and address of the owner or operator;
- The address of the affected source;
- Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;
- Emission control equipment; and
- Fuel used.

[October 27, 2017]

3.47 In accordance with 40 CFR 60.4245(d), the permittee shall submit a copy of each performance test as conducted in §60.4244 within 60 days after the test has been completed.

[October 27, 2017]

3.48 In accordance with 40 CFR 60.4246, the permittee shall comply with the following applicable General Provisions of 40 CFR 60:

Table 3.6 Table 3 to Subpart JJJJ of Part 60—Applicability of General Provisions to Subpart JJJJ

General Provision Citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4248.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4245.
§60.8	Performance tests	Yes	Except that §60.8 only applies to owners and operators who are subject to performance testing in subpart JJJJ.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	Yes	Requirements are specified in subpart JJJJ.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	No	
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

[October 27, 2017]

3.49 Unless expressly provided otherwise, any reference in this permit to any document identified in IDAPA 58.01.01.107.03 shall constitute the full incorporation into this permit of that document for the purposes of the reference, including any notes and appendices therein. Documents include, but are not limited to:

- Standards of Performance for Stationary Spark Ignition Internal Combustion Engines, 40 CFR Part 60, Subpart JJJJ
- National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT), 40 CFR Part 63, Subpart ZZZZ

For permit conditions referencing or cited in accordance with any document incorporated by reference (including permit conditions identified as NSPS or NESHAP), should there be any conflict between the requirements of the permit condition and the requirements of the document, the requirements of the document shall govern, including any amendments to that regulation.

[October 27, 2017]

4 General Provisions

General Compliance

4.1 The permittee has a continuing duty to comply with all terms and conditions of this permit. All emissions authorized herein shall be consistent with the terms and conditions of this permit and the "Rules for the Control of Air Pollution in Idaho." The emissions of any pollutant in excess of the limitations specified herein, or noncompliance with any other condition or limitation contained in this permit, shall constitute a violation of this permit, the "Rules for the Control of Air Pollution in Idaho," and the Environmental Protection and Health Act (Idaho Code §39-101, et seq.)

[Idaho Code §39-101, et seq.]

4.2 The permittee shall at all times (except as provided in the "Rules for the Control of Air Pollution in Idaho") maintain in good working order and operate as efficiently as practicable all treatment or control facilities or systems installed or used to achieve compliance with the terms and conditions of this permit and other applicable Idaho laws for the control of air pollution.

[IDAPA 58.01.01.211, 5/1/94]

4.3 Nothing in this permit is intended to relieve or exempt the permittee from the responsibility to comply with all applicable local, state, or federal statutes, rules, and regulations.

[IDAPA 58.01.01.212.01, 5/1/94]

Inspection and Entry

4.4 Upon presentation of credentials, the permittee shall allow DEQ or an authorized representative of DEQ to do the following:

- Enter upon the permittee's premises where an emissions source is located, emissions-related activity is conducted, or where records are kept under conditions of this permit;
- Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;
- Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
- As authorized by the Idaho Environmental Protection and Health Act, sample or monitor, at reasonable times, substances or parameters for the purpose of determining or ensuring compliance with this permit or applicable requirements.

[Idaho Code §39-108]

Construction and Operation Notification

4.5 This permit shall expire if construction has not begun within two years of its issue date, or if construction is suspended for one year.

[IDAPA 58.01.01.211.02, 5/1/94]

4.6 The permittee shall furnish DEQ written notifications as follows:

- A notification of the date of initiation of construction, within five working days after occurrence; except in the case where pre-permit construction approval has been granted then notification shall be made within five working days after occurrence or within five working days after permit issuance whichever is later;

- A notification of the date of any suspension of construction, if such suspension lasts for one year or more;
- A notification of the anticipated date of initial start-up of the stationary source or facility not more than sixty days or less than thirty days prior to such date; and
- A notification of the actual date of initial start-up of the stationary source or facility within fifteen days after such date; and
- A notification of the initial date of achieving the maximum production rate, within five working days after occurrence - production rate and date.

[IDAPA 58.01.01.211.03, 5/1/94]

Performance Testing

4.7 If performance testing (air emissions source test) is required by this permit, the permittee shall provide notice of intent to test to DEQ at least 15 days prior to the scheduled test date or shorter time period as approved by DEQ. DEQ may, at its option, have an observer present at any emissions tests conducted on a source. DEQ requests that such testing not be performed on weekends or state holidays.

4.8 All performance testing shall be conducted in accordance with the procedures in IDAPA 58.01.01.157. Without prior DEQ approval, any alternative testing is conducted solely at the permittee's risk. If the permittee fails to obtain prior written approval by DEQ for any testing deviations, DEQ may determine that the testing does not satisfy the testing requirements. Therefore, at least 30 days prior to conducting any performance test, the permittee is encouraged to submit a performance test protocol to DEQ for approval. The written protocol shall include a description of the test method(s) to be used, an explanation of any or unusual circumstances regarding the proposed test, and the proposed test schedule for conducting and reporting the test.

4.9 Within 30 days, or up to 60 days when requested following the date in which a performance test required by this permit is concluded, the permittee shall submit to DEQ a performance test report. The written report shall include a description of the process, identification of the test method(s) used, equipment used, all process operating data collected during the test period, and test results, as well as raw test data and associated documentation, including any approved test protocol.

[IDAPA 58.01.01.157, 4/5/00]

Monitoring and Recordkeeping

4.10 The permittee shall maintain sufficient records to ensure compliance with all of the terms and conditions of this permit. Monitoring records shall include, but not be limited to, the following: (a) the date, place, and times of sampling or measurements; (b) the date analyses were performed; (c) the company or entity that performed the analyses; (d) the analytical techniques or methods used; (e) the results of such analyses; and (f) the operating conditions existing at the time of sampling or measurement. All monitoring records and support information shall be retained for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Supporting information includes, but is not limited to, all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. All records required to be maintained by this permit shall be made available in either hard copy or electronic format to DEQ representatives upon request.

[IDAPA 58.01.01.211, 5/1/94]

Excess Emissions

4.11 The permittee shall comply with the procedures and requirements of IDAPA 58.01.01.130–136 for excess emissions due to start-up, shut-down, scheduled maintenance, safety measures, upsets, and breakdowns.

[IDAPA 58.01.01.130–136, 4/5/00]

Certification

4.12 All documents submitted to DEQ—including, but not limited to, records, monitoring data, supporting information, requests for confidential treatment, testing reports, or compliance certification—shall contain a certification by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete.

[IDAPA 58.01.01.123, 5/1/94]

False Statements

4.13 No person shall knowingly make any false statement, representation, or certification in any form, notice, or report required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.125, 3/23/98]

Tampering

4.14 No person shall knowingly render inaccurate any monitoring device or method required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.126, 3/23/98]

Transferability

4.15 This permit is transferable in accordance with procedures listed in IDAPA 58.01.01.209.06.

[IDAPA 58.01.01.209.06, 4/11/06]

Severability

4.16 The provisions of this permit are severable, and if any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

[IDAPA 58.01.01.211, 5/1/94]

Stanford Report

March 13th, 2024| Science & Engineering

Methane emissions from U.S. oil and gas operations cost the nation $10 billion per year

Stanford-led research shows methane emissions from a large share of U.S. oil and gas facilities are three times higher on average than the level predicted by official government estimates.

Researchers collected approximately 1 million aerial measurements of U.S. wells, pipelines, storage, and transmission facilities in six of the nation's most productive regions. (Image credit: Carbon Mapper)



Researchers collected approximately 1 million aerial measurements of U.S. wells, pipelines, storage, and transmission facilities in six of the nation's most productive regions. (Image credit: Carbon Mapper)



The researchers used two different but complementary approaches to measuring methane emissions from specific facilities via airplane-borne sensors. (Image credit: Carbon Mapper)

Oil and gas operations across the United States are emitting more than 6 million tons per year of methane, the main component of natural gas and the most abundant greenhouse gas after carbon dioxide, according to Stanford-led research **published** March 13 in *Nature*.

These emissions, which result from both intentional vents and unintentional leaks, amount to $1 billion in lost commercial value for energy producers. The annual cost rises to $10 billion when researchers account for harm to the economy and human well-being caused by adding this amount of heat-trapping methane to Earth's atmosphere.

Data and code

Brandt and team have made their **code** available for download. Carbon Mapper data can be downloaded from the organization's website. Anonymized data are also available, in certain cases, by request from Kairos Aerospace.

The new emission and cost estimates are roughly three times the level predicted by the U.S. government. The results are based on approximately 1 million aerial measurements of U.S. wells, pipelines, storage, and transmission facilities in six of the nation's most productive regions, including the Permian and Forth Worth in Texas and New Mexico; California's San Joaquin basin; Colorado's Denver-Julesburg basin; Pennsylvania's section of the Appalachian basin; and Utah's Uinta basin. In all, the infrastructure surveyed in this study accounts for 52% of U.S. onshore oil production and 29% of gas production.

Troubling trends

Emissions in three of the six regions were well above expected values. The New Mexico portion of the Permian Basin was by far the highest emitter, with nearly 10% of total methane volume produced in 2019 going straight to the atmosphere. Surveys of some other regions, however, revealed emission rates well below U.S. EPA Greenhouse Gas Inventory estimates based on national averages, suggesting that good practices can reduce emissions.

"Costs aside, the main message here is that some regions show emissions at rates well above those the government itself uses to estimate methane losses," said senior study author **Adam Brandt**, an associate professor of Energy Science & Engineering at the **Stanford Doerr School of Sustainability**. "We hope this will spur government methane inventories toward greater incorporation of remote sensing data at the heart of those estimates."

Methane breaks down faster than carbon dioxide, but it is about 80 times more powerful than CO_2 when it comes to trapping heat during its first 20 years in our atmosphere. In that time frame, climate damage from the 6 million tons of annual methane emissions found in this study is roughly equivalent to a full year of carbon emissions from all fossil fuel use in Mexico.

Because methane can trap so much heat in the short term, accurate assessments of methane leaks are key to predicting the impacts of climate change that will be felt in our lifetime and verifying emissions reductions at a time when the U.S. and more than 100 other countries have pledged to cut emissions 30% below 2020 levels by 2030.

Eyes in the sky

By showing that leaks cost industry more than a billion dollars a year, the researchers hope to gain producers' attention and motivate them to voluntarily stop emissions at their own facilities as a cost-saving measure. Additionally, the researchers say total costs from methane leaks and vents in the six-region study area are likely much higher, as the survey covered less than half of the facilities in the area.

The authors found fewer than two percent of emitters are responsible for 50 to 80% of emissions in all surveyed regions except for Colorado's Denver-Julesburg basin and Utah's Uinta basin. In terms of types of production facilities most likely to leak, the study noted that midstream infrastructure was responsible for about half of total emissions, which is higher than previous estimates. Midstream infrastructure includes gathering and transmission pipelines, compressor stations, and gas processing plants that shuttle gas from the wells to cities and towns.

"Solving the methane challenge is not quite as easy as simply finding and fixing a handful of leakers, as these stark numbers might suggest, but it does mean that efforts concentrated on relatively few operations could have considerable benefits," said lead study author, **Evan Sherwin**, a research scientist at Lawrence Berkeley National Laboratory who worked on the research as a postdoctoral scholar in Brandt's lab at Stanford.

"Climate change mitigation starts with better tracking of emissions, of course, but also accurate tracking of reduction efforts going forward."

- Adam Brandt - Associate Professor of Energy Science & Engineering

Measurement matters

The research combined direct aerial measurements with an emissions simulation tool **developed in Brandt's group at Stanford** by study co-author **Jeffrey Rutherford**, PhD '22, to estimate the emissions that would be too small for the aircraft to reliably detect. The companies Kairos Aerospace and Carbon Mapper provided two different but complementary approaches to measuring methane emissions from specific facilities via airplane-borne sensors.

Total estimated leaked emissions range from just less than one percent to as much as 9.6% of total volume, with an average of 3% across the surveyed regions. The federal government estimates that methane emissions from oil and gas facilities nationwide average roughly 1% of gas production. Sherwin noted that in the surveyed regions of Pennsylvania and Colorado, the team's estimates were on par with or lower than **estimates from the U.S. Environmental Protection Agency**.

"Climate change mitigation starts with better tracking of emissions, of course, but also accurate tracking of reduction efforts going forward," Brandt said. "The method introduced here offers a path to combining measurements at several scales to greatly improve inventories that should lead us to much better tracking of those important reductions critical to national mitigation commitments."

Brandt is also faculty director of the Stanford Natural Gas Initiative and a senior fellow at the **Stanford Precourt Institute for Energy**. Rutherford is now employed at Highwood Emissions Management. Additional Stanford co-authors include Energy Science & Engineering PhD students **Zhan Zhang** and **Yuanlei (Yulia) Chen**. Other coauthors are affiliated with Kairos Aerospace, Carbon Mapper, University of Arizona, and NASA Jet Propulsion Laboratory.

This study was funded by the Stanford Natural Gas Initiative, NASA's Carbon Monitoring System and Advanced Information System Technology programs, Carbon Mapper, RMI, the Environmental Defense Fund, the California Air Resources Board, the University of Arizona, the U.S. Climate Alliance, Arizona State University's **Global Airborne Observatory**, and the Mark Martinez and Joey Irwin Memorial Public Projects Fund with the support of the Colorado Oil and Gas Conservation Commission, the Colorado Department of Public Health and Environment. Portions of this research were carried out under a contract with NASA.

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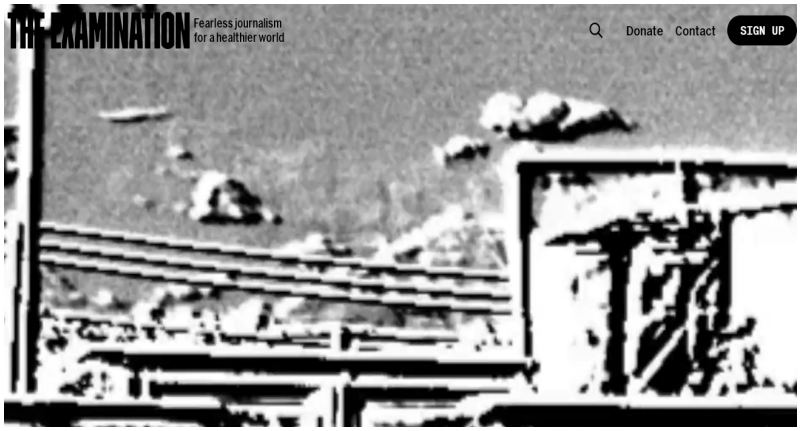
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◇ INDUSTRIAL POLLUTION

Oil companies leak toxic gas across Texas – making local residents sick

Infrared video shows gas laced with hydrogen sulfide leaking from tanks across from the Hinojos family home in Odessa, Texas on Sept. 13, 2022. (Source: Texas Commission on Environmental Quality)

Tens of thousands of people live close to oil and gas wells where they risk exposure to hazardous levels of hydrogen sulfide. Regulators do little to protect them.

By Will Evans, Caroline Ghisolfi *and* Amanda Drane June 12, 2024

This story is published in partnership with the Houston Chronicle.

Before dawn on a fall day in 2022, Texas air analysts approached a mobile monitoring van parked on the edge of Odessa, in West Texas.

They were hit with the stench of rotten eggs, the telltale sign of hydrogen sulfide. The invisible poisonous gas had seeped in, saturating the van.

Breathing it in, the state workers grew sick: racing heartbeats, headaches, nausea. Their equipment had picked up what internal notes would later call “insanely high” levels of gas in the neighborhood.

The analysts fled.

Next door, Vanessa and Victor Hinojos were just starting their day with their two young children. No one told them that hydrogen sulfide levels outside their home had soared to 82 times the Texas limit for a residential area.

And no one has stopped it yet.



The Hinojos family home is located near a cluster of wells and tanks, operated in recent years by Cambrian Management, in Odessa, Texas. The Examination

Across Texas, oil companies are belching hydrogen sulfide gas into communities, near families and schools, with few or no repercussions, an investigation by The Examination and the Houston Chronicle has found.

The state has a limit for hydrogen sulfide in the air, but regulators broadly disregard it, downplaying the health threats, the investigation found. At two sites in the Permian Basin alone, gas levels exceeded the state limit 1,590 times since the state started measuring in 2020.

Outside the Hinojos home, independent testing by the news organizations this spring detected hydrogen sulfide levels frequently soaring past the state limit.

Known as H2S, the fumes escape from aging oil and wastewater tanks scattered within this community in the heart of the Permian Basin — one of the most productive oil fields in the world.

Extremely high concentrations of hydrogen sulfide can kill quickly, but less attention has been paid to those breathing in lower levels of the gas in their daily lives. Studies have linked chronic low-level H2S exposure to neurological and other health problems.

The Hinojos family and other Texans living near facilities leaking the gas describe a litany of ailments, including headaches, nausea, eye and nose irritation, coughing, asthma and rashes.

The Railroad Commission of Texas, which regulates the oil industry, doesn't map storage tanks or the locations of dangerous hydrogen sulfide concentrations.

The Houston Chronicle and The Examination mapped for the first time more than 54,000 wells in Texas that are associated with high enough concentrations of the gas to be "immediately dangerous to life or health," if the gas were to leak and people were exposed directly.

An estimated 78,000 people live within half a mile of those wells, according to an analysis of Railroad Commission data and U.S. Census population estimates by the National Aeronautics and Space Administration.

Eighty-eight schools are in the same footprint.

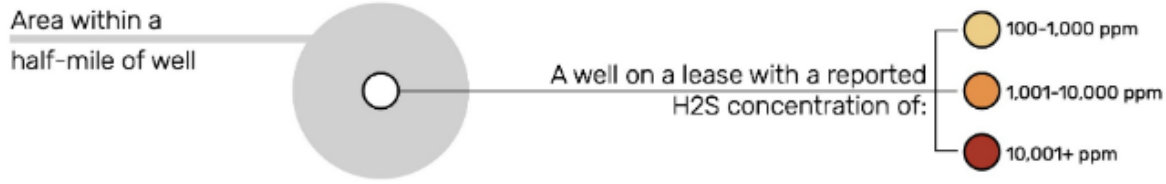
"This is a major concern," said Rui Wang, dean of the faculty of science at York University in Toronto and a leading researcher on H2S. "If the people live in the radius of a half mile, they will be affected by those leaks. If there is a serious leak, their health definitely is a concern."

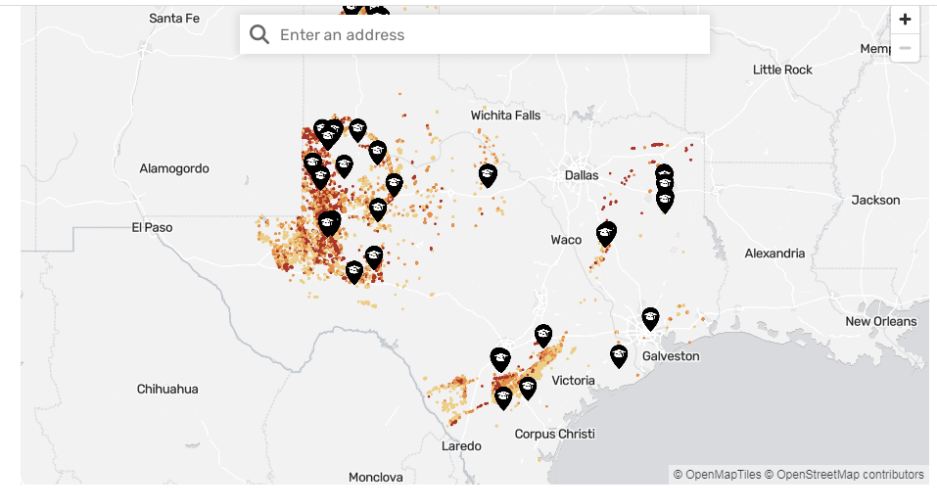
Even residents outside the half-mile radius could be affected, Wang said. The degree of risk that residents face depends on how much gas escapes, how far away they live, weather and wind direction.

Are there high concentrations of hydrogen sulfide near your home? Search your address.

The Houston Chronicle and The Examination mapped out every active well in Texas that belongs to oil or gas-producing sites with reported hydrogen sulfide concentrations of 100 parts per million or more. That level is "immediately dangerous to life or health" if the gas escapes from the wells and storage tanks where it is measured, and you are exposed directly.

An estimated 78,000 people live within a half mile of wells on those sites, and at least 33,600 students go to school in that same footprint.





Note: Operators of production sites, also known as "leases," must report just one H2S measurement per lease. Measurements shown on this map may have been taken several miles away from any specific well on large leases.

If a leak happens, the level of risk you may face depends on the size of the leak, distance from the source of the leak, weather and wind. The map doesn't indicate whether or where the gas is leaking.

A review of hundreds of investigation files from the Railroad Commission and the Texas Commission on Environmental Quality, which oversees air quality, shows that residents struggle to get help and when Texas inspectors find the gas venting into the air, companies seldom face penalties.

Instead of making repeat offenders upgrade their facilities, inspectors return to the same leaking oil tanks again and again as problems persist for years.

"The impact to the general population should not be underestimated," said Gunnar Schade, an associate professor at Texas A&M University who studies oil-field air pollution. "It's so toxic and so dangerous."

Schade called the high levels of hydrogen sulfide in residential areas "shocking" and said when a monitor picks up the gas at one level, that suggests that it's swirling through the community at possibly much higher levels elsewhere. Nobody should be living close to the facilities, he said.

Yet there are only three sites in the Permian Basin where the state continuously tests the air for hydrogen sulfide.

One is at Odessa's Murry Fly Elementary School, where a statue of a spurting oil derrick displays the school's nickname, the Oilers. Measured near a playground with seesaws and slides, airborne hydrogen sulfide levels have broken the state limit 185 times since 2020. But the principal said he was never warned.

Asked how it keeps residents safe, the Texas Commission on Environmental Quality said it uses its Air Pollutant Watch List to focus resources on areas with "elevated concentrations of

air toxics.” But the agency hasn’t added to that list since 2007, ignoring the shale boom that has brought an explosion of oil and gas activity across the state since then. It doesn’t include the Hinojos family’s neighborhood or any other site in the Permian Basin.

TCEQ spokesperson Victoria Cann said the agency investigates complaints, and “when violations are identified, a penalty may, or may not, be appropriate to assess.” She said the agency uses its monitoring system, the watch list and a permitting process “to ensure that ambient air toxic concentrations are at levels that are protective of public health and welfare.” Cann added that the agency communicates with “local industry” when monitoring stations find elevated readings and notifies emergency responders when there is an imminent health risk.

The Railroad Commission “takes its mission to protect communities and the environment very seriously, and any implication otherwise is false,” spokesperson Patty Ramon said in an email statement. “We continuously monitor facilities, especially those near schools or neighborhoods, to ensure safety.”

The commission conducts a large number of inspections at sensitive sites, including 70 near the Hinojos house in recent years, the statement said. When inspectors find violations, they work to make sure companies resolve them as quickly as possible, it added.



A flare burns near the home of Vanessa and Victor Hinojos as their children play in the yard on Wednesday, March 6, 2024, in Odessa, Texas.

Photo by Elizabeth Conley for the Houston Chronicle

Meanwhile, the Hinojos family, from their toddler to the grandparents who live next door, continues to breathe in the neighborhood air laced with putrid gas. Some of them get regular headaches and occasional nausea and worry about the long-term effects. And they can’t get anyone to put a stop to it.

“There’s a whole neighborhood out there, a whole community, and we all suffer from it,” Vanessa Hinojos said. “It’s very concerning and frustrating and worrying.”

Safety lagging as H2S spreads

In his 30 years patrolling oil fields for the Railroad Commission, Sam Birdwell said he regularly found significant levels of hydrogen sulfide venting from oil facilities in residential areas, near schools, churches and houses. Sometimes his personal H2S alarm — set to warn him to leave the area — would go off at someone’s front door.

“Can you imagine being old and not being able really to get out of your home?” said Birdwell, who was the statewide hydrogen sulfide coordinator before he retired in 2020. “For someone elderly or people with newborns — that’s the kind of stuff that keeps me awake.”

Birdwell is no environmental activist, and doesn’t want to be associated with any. He grew up rough on a ranch in Deep East Texas, and still, at 71, herds cows on the side. He learned the oil industry laying pipelines and roughnecking at the top of a drilling rig. He has no problem with pumping oil, but he believes it should be done right.

Over the past 16 years, the shale boom has tapped vast new quantities of oil, making West Texas’ Permian Basin so prolific it pumps out more than 40% of the country’s oil. The region is naturally saturated with hydrogen sulfide. Fracking and injecting water to push out more oil also has helped spread hydrogen sulfide to new areas that didn’t have it before.

While not all oil fields are bedeviled by hydrogen sulfide, the gas affects workers and communities in other oil-rich regions around the world, from Canada to Iraq to Kazakhstan. It also plagues other industries, such as paper mills, and can build up in any storage area with decaying material like manure or sewage.

In the Permian Basin, increased oil production has boosted the population, bringing more people to live close to wells and storage tanks.

Technical solutions to capture or treat the gas are available but expensive, and companies often rely on flaring it instead, burning off the hydrogen sulfide but producing other kinds of unhealthy pollution.

“In my 30 years of experience,” Birdwell said, “it’s always been down to a matter of money.”

Birdwell was in charge of regulations born of tragedy.

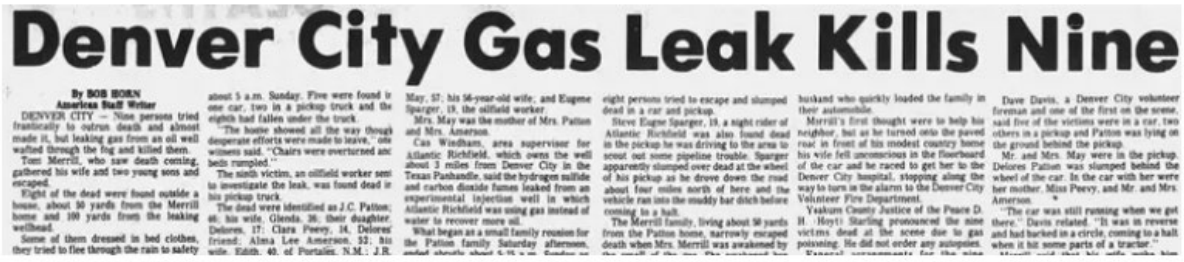
In 1975, an oil-field leak of hydrogen sulfide killed nine people, including two teenage girls, in the small West Texas town of Denver City. Some victims were found slumped over in vehicles, struck down as they tried to get away.

The catastrophe prompted Texas to tighten its safety regulations governing the gas. Known as Rule 36, the rules require energy companies operating in high H2S areas to measure concentrations, train their employees, put up warning signs and, in some cases, monitor for leaks



Sam Birdwell, 71, spent 30 years patrolling oil fields for the Texas Railroad Commission, where he was most recently the statewide hydrogen sulfide coordinator.

Photo by Alyssa Hartley for The Examination



Denver City Gas Leak Kills Nine

By BOB BORN
American Staff Writer

DENVER CITY — Nine persons tried frantically to outrun death and almost made it, but leaking gas from an oil well wafted through the fog and killed them.

Tom Merrill, who saw death coming, gathered his wife and two young sons and escaped.

Eight of the dead were found outside a house, about 50 yards from the Merrill home and 100 yards from the leaking wellhead.

Some of them dressed in bed clothes, they tried to flee through the rain to safety about 5 a.m. Sunday. Five were found in one car, two in a pickup truck and the eighth had fallen under the truck.

"The home showed all the way though desperate efforts were made to leave," one witness said. "Chairs were overturned and beds rumpled."

The ninth victim, an oilfield worker sent to investigate the leak, was found dead in his pickup truck.

The dead were identified as J.C. Patton, 48, his wife, Glenda, 36; their daughter, Delores, 17; Clara Peevy, 14, Delores' friend; Alma Lee Amerson, 53; his wife, Edith, 40, of Portales, N.M.; J.R. May, 57; his 56-year-old wife; and Eugene Sparger, 19, the oilfield worker.

Mrs. May was the mother of Mrs. Patton and Mrs. Amerson.

Cas Windham, area supervisor for Atlantic Richfield, which owns the well about 3 miles from Denver City in the Texas Panhandle, said the hydrogen sulfide and carbon dioxide fumes leaked from an experimental injection well in which Atlantic Richfield was using gas instead of water to recover more oil.

What began as a small family reunion for the Patton family Saturday afternoon, ended about 5:30 a.m. Sunday as eight persons tried to escape and slumped dead in a car and pickup.

Steve Eugne Sparger, 19, a night rider of Atlantic Richfield was also found dead in the pickup he was driving to the area to scout out some pipeline trouble. Sparger apparently slumped over dead at the wheel of his pickup as he drove down the road about four miles north of here and the vehicle ran into the muddy bar ditch before coming to a halt.

The Merrill family, living about 50 yards from the Patton home, narrowly escaped death when Mrs. Merrill was awakened by husband who quickly loaded the family in their automobile.

Merrill's first thought were to help his neighbor, but as he turned onto the paved road in front of his modest country home his wife fell unconscious in the floorboard of the car and he raced to get her to the Denver City hospital, stopping along the way to turn in the alarm to the Denver City Volunteer Fire Department.

Yoakum County Justice of the Peace D. H. (Hoyt) Starling pronounced the nine victims dead at the scene due to gas poisoning. He did not order any autopsies.

Dave Davis, a Denver City volunteer fireman and one of the first on the scene, said five of the victims were in a car, two others in a pickup and Patton was lying on the ground behind the pickup.

Mr. and Mrs. May were in the pickup. Delores Patton was slumped behind the wheel of the car. In the car with her were her mother, Miss Peevy, and Mr. and Mrs. Amerson.

"The car was still running when we got there," Davis related. "It was in reverse and had backed in a circle, coming to a halt when it hit some parts of a tractor."

In 1975, an oilfield leak of hydrogen sulfide killed nine people, including two teenage girls, in the small West Texas town of Denver City.

The Odessa American

Over time, Birdwell came to believe that the rule needed updating to protect the public.

“The rule itself needs some teeth and some muscle and blood in it,” Birdwell said. “We’re looking at damn near 50 freaking years without addressing that rule.”

Birdwell said he was hampered in his ability to stop companies from releasing toxic gas near people.

At most, Birdwell said, he could order short-term shutdowns and require companies to flare their gas for safety reasons. But the flares themselves would sometimes go out, releasing more gas freely billowing into the air.

"You needed to be able to have the authority to say, 'Thou shalt not vent right here, brother,'" Birdwell said. "If it's anywhere near a populated area, you should not be venting hydrogen sulfide gas at all."

Birdwell said he made the case for a rule update to the commission chairman, Christi Craddick, who tasked him with working on a proposed revision. He said he sent his recommendation to headquarters before he retired. Craddick's office confirmed that she requested it but said they didn't have records that they received it.

"However," Craddick said in a statement, "we continue to require operators to implement safety measures that protect employees and the public from potential exposure to H2S gas, or face enforcement actions."

In a January Facebook post, Craddick, who is running for another term on the Railroad Commission, said, "2023 was another banner year for Texas oil and gas, thanks to the Railroad Commission's commitment to reasonable regulation."

Residents' repeated complaints go unaddressed

The files of Texas' environmental agency are sprinkled with gas-related complaints from residents living near oil wells and tanks: "Strong odor from oil and gas facility causing nausea"; "Unusually strong h2s odor encountered around and inside the complainants home"; "strong smell of sour gas in the area that is seeping into the home and causing health effects."

But in Ector County, where the Hinojos family lives, the majority get dismissed after a single visit, according to available TCEQ records from the last six years. The agency commonly closes complaints if inspectors don't detect the gas at the precise time they visit, even though levels fluctuate with weather, wind and oil operations, and are often worse at night when inspectors are not there.

Vanessa Hinojos, however, has not been deterred, repeatedly filing complaints for years. Over time, state inspectors have repeatedly found Cambrian Management, longtime operators of the facility across the street from her home, was leaking the toxic gas in violation of state regulations.

TIMELINE:

One family's fight against toxic H2S gas leaks in West Texas

The Hinojos family has something of a dream house in Odessa. Inside, on a giant wraparound couch facing a TV and fireplace, they watch the Dallas Cowboys and play with their baby. Outside, the older kids, ages 12 and 13, swing on a wooden play structure and bounce on a trampoline next to the family's dogs, chickens, goat and pony. Grandparents live next door, with a swimming pool for hot summer days.

But like many homes in Odessa, the house sits in the middle of an oil field. Across the street on one side, tall, weathered 500-barrel tanks store oil and water pumped from nearby wells, and on another, a torch-like flare juts up 35 feet into the sky, constantly burning gas in curling flames.



A flare burns off excess gas, including methane and hydrogen sulfide, across the street from the Hinojos family house, on Wednesday, March 6, 2024, in Odessa, Texas.

Video by Elizabeth Conley for the Houston Chronicle

"It's a very strong, stinky smell," said their 12-year-old son, sporting a Spider-Man T-shirt, before going outside to jump on the trampoline.

"It bothers us a lot," said their curly-haired 13-year old daughter, whose schedule is packed with soccer, tennis and track. "Like sometimes the smell gives me headaches and stuff."

Vanessa Hinojos' family bought this patch of land in the 1990s, cleaned it up, planted trees and lived in mobile homes as they saved money to build. It didn't smell like this back then, they said. It took years to put together the large, well-appointed houses they live in. Now, they fear they need to move to protect their children's health.

Hinojos' husband knows about H2S from working in the oil fields. But the smell is much worse at home, and he has better protection at work, he said. He took an H2S monitor home, recording a video of it sounding an alarm from high levels of the gas across the street from their house.

Vanessa Hinojos, a busy mom juggling her job at a bank with her kids' activities and appointments, said she worries all the time: "What kind of damage is it doing to my children?"

She has reached out to the Railroad Commission and TCEQ numerous times since 2017 about the smells and her family's suffering health, records show.

Sometimes, inspectors have come out and found H2S leaking from damaged tank hatches, a common problem because the corrosive gas eats away at seals as well as metal. Other times, it was streaming from an unlit flare. At one point, TCEQ fined Cambrian $7,600. When inspectors found violations, the company typically made repairs piecemeal.

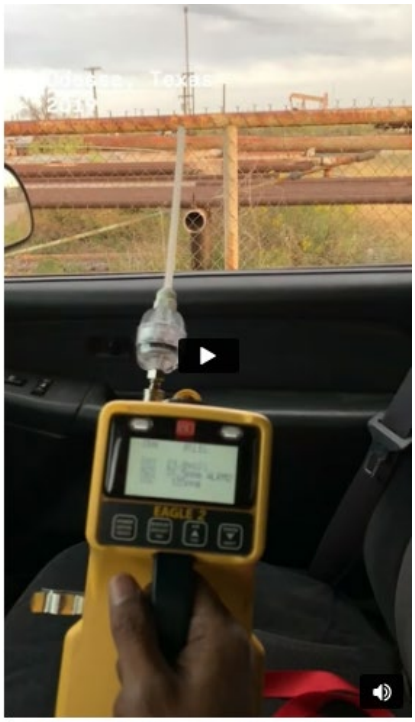
But still, the gas kept leaking.

Sometimes inspectors showed up and didn't identify a problem. More than once, inspectors fled as their monitors picked up alarming levels of H2S.

In September 2022, a TCEQ investigator responding to a complaint fled the scene so fast when his personal alarm sounded that he wasn't sure how high the reading was.

"Those hatches were still leaking pretty bad and we had elevated levels of H2S still coming off site," the inspector wrote to Alan Means, Cambrian's owner, that October.

"We are sending them back to enforcement for venting the flare again," wrote Ryan Slocum, a TCEQ manager, in an internal email. "The tanks continue to leak. We have a meeting with the owner this afternoon to discuss the site at our office and to urge them into compliance. This site has documented many violations over the past month."



In 2019, Victor Hinojos took an H2S monitor home, recording a video of it sounding from high levels of the gas across the street from their house.

Provided by Victor Hinojos



This oil and wastewater storage facility long operated by Cambrian Management sits across the street from the Hinojos family house on March 6, 2024, in Odessa, Texas.

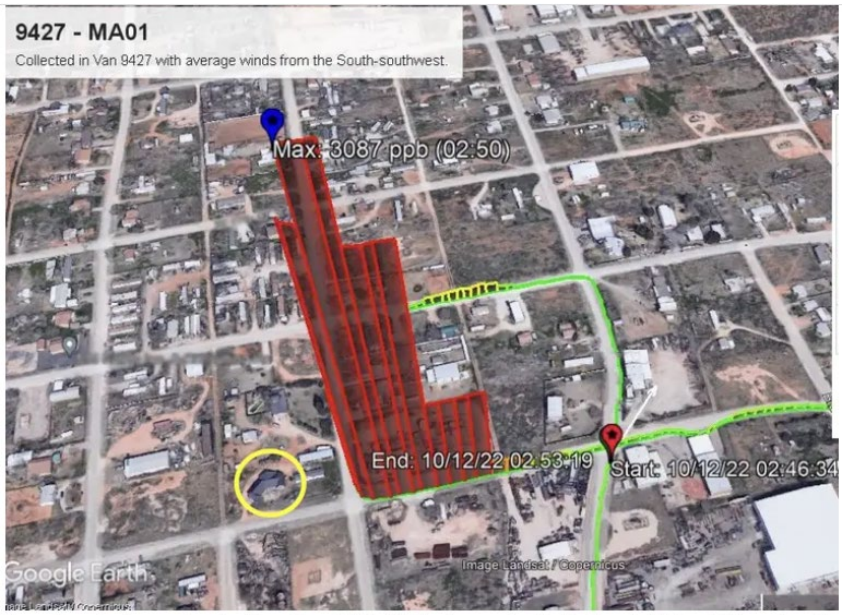
Photo by Elizabeth Conley for the Houston Chronicle

Slocum asked for the mobile team to pay a visit on its trip through West Texas. As the team's monitoring van passed the intersection near the Hinojos house one night, it suddenly hit a "dramatic spike" of H2S and "immediately evacuated," according to the team's notes.

Soon after, another van picked up H2S levels near the same spot that prompted analysts to put on special masks and flee in an "escape vehicle" to avoid being exposed themselves.

“I get why y’all were so freaked!” their team leader messaged them afterward.

“Y’all stay safe,” an agency official emailed the team.



Texas air analysts encountered a “dramatic spike” in H2S levels near the Hinojos home in October 2022, as shown in this image created by the Texas Commission on Environmental Quality’s mobile monitoring team. The Hinojos house is labeled with a yellow circle by The Examination.

Source: Texas Commission on Environmental Quality

The next day — outside the Hinojos house — the van picked up the highest readings yet: 62 parts per million. The concentration of H2S was stronger than the maximum level allowed by the Occupational Safety and Health Administration for oil-field workers. The analysts had stayed away, measuring the gas remotely for safety, and became sick with the fumes when they came back to the van.

Cambrian determined that the underground pipeline from the tanks to the flare was leaking and would be replaced. Over the next few days, inspectors kept coming back and finding more H2S. At one point, they talked to people who live on the other side of the tanks who said the smell was “overpowering” but didn’t want to file a complaint.



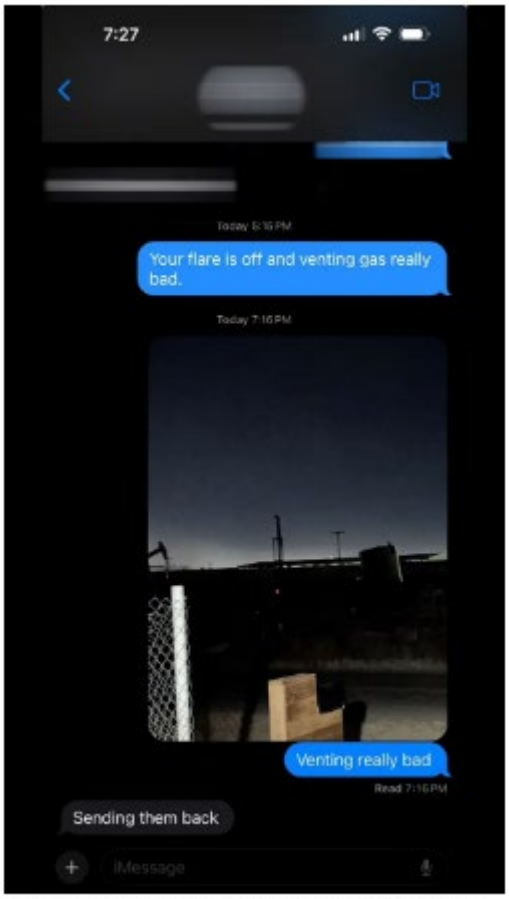
An unlit flare leaks gas, as shown in an infrared video taken by state inspectors on May 19, 2023, across the street from the Hinojos family home in Odessa, Texas. Footage obtained by public records request.

Source: Texas Commission on Environmental Quality

Eventually, in May 2023, the agency issued a “notice of enforcement,” which can lead to fines, though it’s still pending. Later the same month, responding to another Hinojos complaint, inspectors found the gas spewing, once again, from the tanks and one of the flares.

This time the company said birds had nested there and broke the spark plug. Because the company came to fix the violations, TCEQ resolved it without a penalty. The agency currently lists the company’s compliance record as “satisfactory.”

Cann, the TCEQ spokesperson, said the agency didn’t take enforcement action that time because “health effects were not documented,” whereas in the earlier incident an inspector had gotten sick.



Victor Hinojos texts with a company representative on Jan. 28, 2024.

Provided by Hinojos family

This year, Hinojos and her husband repeatedly exchanged texts with a company representative, asking for help. “Hey it’s been smelling really bad the last couple days and it’s shifted to our house,” she texted in January. Her husband sent a photo of the unlit flare. The company contact responded that he’d send someone back to the site.

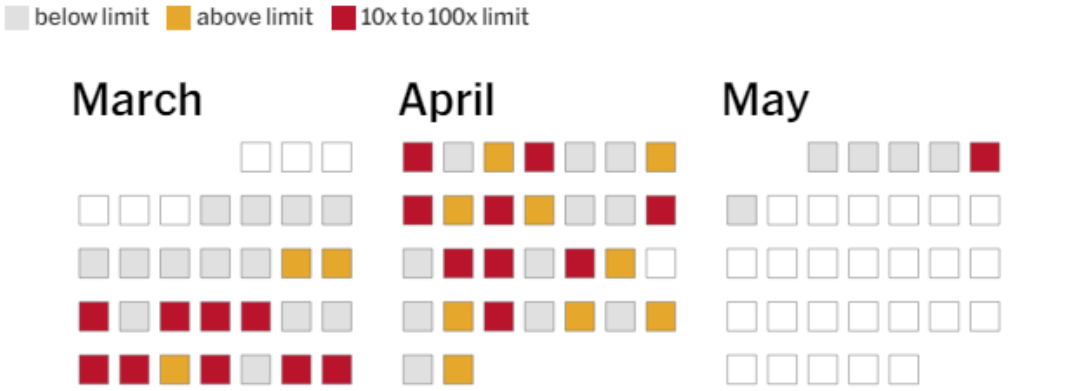
In February, the smell woke her up with a bad case of nausea in the middle of the night. She filed yet another complaint with TCEQ.

An H2S monitor placed by a reporter in the Hinojos yard from March 7 to May 6 detected gas levels above the state limit on more than half the days recorded in that period.

Texas’ limit for residential areas is 0.08 parts per million averaged over 30 minutes.

H2S levels at the Hinojos home regularly exceed the state limit

A hydrogen sulfide monitor placed by a reporter in the Hinojos yard measured levels above the state limit on more than half of the recorded days between March 7 and May 6.



This graphic shows the maximum 30-minute average of readings taken every 15 seconds on each calendar day. The state limit is 0.08 ppm averaged over 30 minutes.

Chart: Caroline Ghisolfi / Houston Chronicle

On one April night, the monitor recorded concentrations of up to 81 parts per million just after midnight, well above the “insanely high” levels that sickened state workers earlier, and approaching the 100 ppm mark considered “immediately dangerous to life or health.” Readings from that half-hour after midnight showed levels 90 times higher than the state’s official limit.

After receiving questions from The Examination and the Chronicle, TCEQ reviewed its files and discovered that Cambrian had never complied with the agency’s 2021 order that came with the $7,600 fine. The company was supposed to provide proof that it was following the rules. The agency sent a follow-up letter in April 2024 asking the company to comply.

‘I never lost an ounce of sleep about somebody getting hurt’

Far from the smell of hydrogen sulfide, on a ranch in McCaulley that stretches for hundreds of acres, Cambrian’s owner, Alan Means, has found his “piece of paradise.”

Wearing a flannel and jeans, with some tobacco tucked in his mouth, Means was busy one day in March building a blacksmith shop to work in for fun in his retirement. Means still co-owns the oil wells and tanks with a group of investors but retired from operations last year, he said. Co-founded by Means in 2001, Cambrian has drilled and operated hundreds of wells in the Permian Basin.



Alan Means of Cambrian Management, which has drilled and operated hundreds of wells in the Permian Basin. As for residents living near Cambrian's facilities, Means said, "We treated everybody as good as we could over there."

The Examination

Means admits that living near the smell of H2S is annoying, but he sees it as more of an irritant than a safety concern.

"It stinks really bad," he said. "If it didn't stink, we wouldn't get any complaints."

He said people tend to blame an oil company when they feel nauseated, but that might not be the cause. It's possible that someone with asthma might be affected by the H2S, he said, or it could be something else. "We treated everybody as good as we could over there," he said.

The site near the Hinojos family has H2S gas that, when contained, has a concentration of 186,400 ppm – more than 200 times the amount that would cause immediate collapse with one or two breaths and death within minutes if the gas were to leak and someone were exposed directly.

But because oil production is low, the volume of gas that could escape doesn't pose a lethal danger to anyone in the community and dissipates quickly, Means said. The levels found by the TCEQ monitoring van, he noted, are well below the "drop dead concentration."

"I never lost an ounce of sleep about somebody getting hurt, because I knew our volumes were so low," he said. "They'd literally have to climb up the tank, drill a hole in the top of it and snort it."

The company reported to the Railroad Commission in 2001 that a catastrophic release of gas from that production site could overlap public areas with potentially life-threatening levels of H2S. Means said that wasn't a realistic scenario.

Schade, of Texas A&M, said the concentrations measured by state analysts and, later, the monitor in the Hinojos family yard were so high, they indicate leaks so large that if someone had been exposed closer to the source it could have been deadly.

“This is crazy,” he said of the levels. “My lord, do people have to die before this changes?”

Acute exposure to hydrogen sulfide rarely kills community members. However, the gas occasionally kills oil-field workers whose jobs require them to be close to the tanks and wells.



A warning sign near a tank in an oil storage facility in an Odessa neighborhood, photographed on March 6, 2024.

Photo by Elizabeth Conley for the Houston Chronicle

One night in October 2019, Jacob Dean went to check on some malfunctioning equipment inside an Odessa pump house, where water is pushed into the ground to produce more oil. The water, like the oil it mixed with, was laced with hydrogen sulfide.

When Dean’s wife, Natalee, couldn’t reach him after a few hours, she went looking for him. Leaving their children, then 6 and 9, in the car outside, she entered the metal building while on the phone with her in-laws. “Oh, my God,” was the last thing they heard her say. The couple’s bodies were found next to each other, killed by a cloud of highly concentrated hydrogen sulfide.

Federal prosecutors have charged the company, Aghorn Operating, and its vice president with violating the Clean Air Act and the Occupational Safety and Health Act as part of a scheme to “enrich themselves by maximizing the production of oil at Aghorn while minimizing costs.”

In the ongoing criminal case, prosecutors have alleged that the company also put the surrounding community at risk: “The hazardous plume traveled beyond the facility at levels

sufficient to adversely impact public health.” People living up to a mile away could have been exposed to enough gas to cause health problems, the government estimated.



A light shines on an Odessa building where, in 2019, oilfield worker Jacob Dean and his wife, Natalee, died from hydrogen sulfide exposure. Federal prosecutors blame the deaths on the oil company, Aghorn Operating, which has pleaded not guilty.

Photo by Elizabeth Conley for the Houston Chronicle

They cited a report by an Environmental Protection Agency toxicologist warning that reported effects of chronic, low-level exposure to the gas include fatigue, incoordination, poor memory, hallucinations, personality changes, shortness of breath and increased visits to the emergency room.

(There are no federal air quality standards for H2S. Under pressure from the industry, the EPA took the gas off its list of “hazardous air pollutants” decades ago, leaving regulation to the states.)

The company and its executive have pleaded not guilty, stating in court filings that “there was no ‘knowing’ release of gas” and rejecting the idea that anyone beyond the facility’s fence line was seriously endangered.

Local independent operators like Aghorn and Means buy old wells from bigger companies after the wells are no longer as profitable. “We’re all bottom feeders. We’re all carp,” Means said. “But it made a living for us.”

Cambrian used to pipe excess gas from its wells to a processor, Means said. Then, in 2017, the company that operated the pipelines, DCP Midstream, now part of Phillips 66, stopped taking any more, citing a “high level of operational risk.” So Cambrian started flaring all the gas, leading to the continuous billowing flame outside the Hinojos house.

In its application for a flaring permit, Cambrian said the alternative — shutting down the site — would “result in economic waste since oil will go unproduced.”

In the meantime, sometimes parts fail, there's a leak and the company fixes it, Means said. "You're going to have issues. I mean, I wish it was fail proof." Over the years, Cambrian has replaced tanks and upgraded the flares, he said, but retrofitting the whole thing would be costly. "Financially, it'd be difficult," he said.

Means said he operated the site until last year, and that his company has transferred day-to-day management to Octane Energy. Cambrian's name is still on the paperwork, but that will eventually change, he said. "It's kind of a bastard deal that I'm trying to get out of," Means said.

Octane's managing partner, Jared Blong, said "poor planning" allowed residential communities to sprout up on known H2S-rich oil fields.

He said modern facilities do a better job preventing leaks but agreed with Means that retrofitting aging tanks doesn't always make economic sense.

"That upgrade may never actually pay for itself," he said.

Blong called his relationships with regulators healthy and collaborative and "focused on solutions as challenges inevitably arise."

'I'm surprised they allow those fumes so close to school'



A pump jack towers over the grounds of Noel Elementary School in Odessa, photographed on March 6, 2024.
Photo by Elizabeth Conley for the Houston Chronicle

On a March afternoon, the foul odor of rotten eggs wafted through another Odessa neighborhood shared by modest, one-story houses, mobile homes and oil tanks. Like the ones near the Hinojos family, these storage tanks are also part of Cambrian Management's oil

business. Neighbors said they've been living with the noxious smell for many years. One pulled out a copy of a complaint he had filed with the state more than a decade earlier.

A breeze carried the smell toward the campus of Noel Elementary School, about 800 feet from the tanks. It's an oil-field school, named after a local oilman, with a dark gray pumpjack on campus looming over the playground's swings and basketball hoops. The company doesn't operate that pumpjack during school hours. But reporters could smell the characteristic H2S odor outside the school building.

Some people in the community write it off as a fact of life in the oil patch, or don't even notice it. Principal Jennie Chavez said the only smells at the school have come from sewage issues with old plumbing. In her eight years at the school, she said, there haven't been any problems or complaints. She said her understanding was that H2S doesn't smell.



Noel Elementary School principal Jennie Chavez, photographed at the school on March 6, 2024, said she hasn't smelled any hydrogen sulfide there or received any complaints.

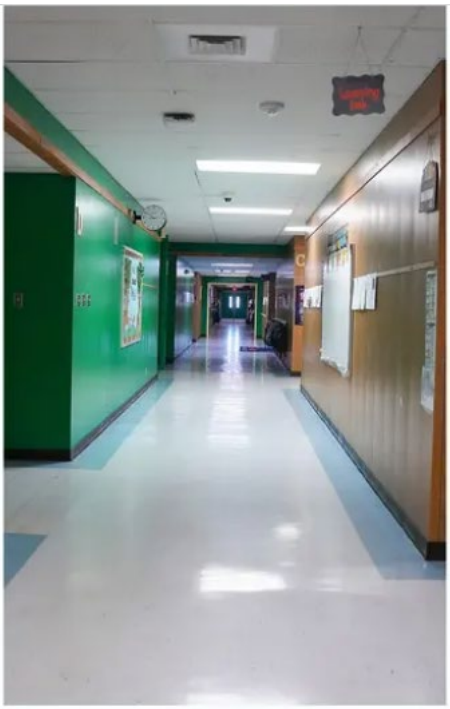
Photo by Elizabeth Conley for the Houston Chronicle

"I've lived here my whole life and I actually grew up a few streets down," said Chavez, wearing red earrings and pants to match a shirt celebrating the Texas college her son attends. "As far as long-term effects, I mean, nothing's happened to me."

There have long been concerns in the neighborhood around Noel Elementary, though. Debra Perrin, whose sister, parents, grandparents, and aunt and uncle were killed in the 1975

hydrogen sulfide disaster spoke out in 1983 to say she was particularly worried about the area near the school. “Haven’t enough lives been lost already?” she wrote to the local paper. When the issue came up in a City Council meeting back then, a councilmember said oil fields are “what made Odessa grow, and we can’t say we’re going to stop the growth because oil wells are in the way.”





Noel Elementary School in Odessa has an H2S alarm in the office, photographed on March 6, 2024. The school principal said she doesn't know what concentration of the gas would set it off.

Photos by Elizabeth Conley for the Houston Chronicle

The school has an H2S alarm system, but Chavez said she doesn’t know what level of gas would set it off. Systems like this can log the levels of gas they detect, but the school’s model doesn’t, so nobody knows to what level of H2S the students are exposed.

In January 2015, a parent called 911 because of the strong smell of H2S at the school. Ten days later, a TCEQ inspector found that an unlit flare at Cambrian’s facility was releasing gases into the air.

In 2016, a motor on the pumpjack near the playground exploded at night, but no one was injured, according to city records. Later that year, the warning lights on the H2S alarm went on. School staff ushered students into the gymnasium during a brief “shelter in place.” Students returned to class after air quality readings came back normal.

At the time, a district official told the Odessa American that overcast days tend to set off the sensors because the gas stays low, but that it dissipates rapidly. Means, Cambrian’s owner,

said in a recent interview that he remembers the alarm was triggered by gas from the sewer system, not his oil facilities. There is no record of a state inspection of the nearby Cambrian facility in the days immediately following the school's "shelter in place."

The month after the shelter in place, someone in the neighborhood complained of "strong odor alleging headaches and congestion" and TCEQ found gas "free flowing" from Cambrian's unlit flare. Inspectors also detected a strong H2S odor but their handheld device did not register it, according to the report.



Air monitors to detect hydrogen sulfide outside of Noel Elementary School in Odessa on March 6, 2024. The system doesn't log the H2S concentrations it detects.

Photos by Elizabeth Conley for the Houston Chronicle

Chavez said she wasn't at the school for any of that. During her time there, the H2S alarm has gone off only when the system malfunctioned, she said.

Between 2015 and 2021, state inspectors found Cambrian's facility near the school venting gases in the neighborhood in violation of state regulations at least 14 times. Neighbors complained repeatedly – worried about their baby, a high-risk pregnancy, and their family's "dry burning eyes," according to inspection records. The Railroad Commission occasionally shut down production at the site until repairs were made, only to find more problems later. The only fine came from TCEQ in 2018, for $4,025, along with an order to "ensure the leaking tank at the Plant is operated and maintained in good working order." In 2023, the agency found that Cambrian hadn't complied with the 5-year-old order and still didn't have authorization to operate there. The agency is investigating the situation, a spokesperson said.

To the west of the school sits another set of wells and tanks, visible across a field of cactus and mesquite. Those belong to Aghorn Operating, the company facing criminal prosecution in the deaths of Natalee and Jacob Dean.

The Railroad Commission found the site in violation of state regulations for releasing H2S on several occasions. Prosecutors in the Dean case cited those leaks and others as part of a conspiracy to cut costs and put “operational convenience” above human health, despite having many facilities near homes, schools and other public areas.

The company “regularly released or ‘vented’ H2S as an accepted way of operating at some Aghorn facilities, by failing to light flares or repair non-functioning flares, or by failing to prevent or repair leaks in tanks, tank hatches or other Aghorn equipment,” prosecutors said.



Noel Elementary School students leave the school at the end of the day on March 6, 2024 in Odessa, pump jack towering over the campus in the background.

Photo by Elizabeth Conley for the Houston Chronicle

At the end of Noel’s school day, students weighed down with backpacks file past the fenced-off pumpjack to a line of buses. Waiting outside to pick up her third grader one afternoon, Megan Chavez said she wishes the children weren’t exposed to H2S.

“I’m surprised they allow those fumes so close to school. Maybe not now, but maybe later in their lives they might have health risks,” said Chavez, sitting in a Toyota Camry with a cross hanging from the rearview mirror.

Chavez noticed the “nasty smell” as soon as she moved to Odessa two years ago for her husband’s oil-field job. Her kids notice it too but don’t know what it is, she said. “They’re poisoning us,” she said. “I have no choice. We have to live here. They have to go to school.”

Eight miles away, another Odessa elementary school does have the ability to track its hydrogen sulfide exposure. In 2020, the year the state environmental commission put a monitoring station at Murry Fly Elementary, it picked up H2S above the state limit 75 times, according to state records. It happened 17 times in the first three months of 2024, preliminary data show.

Principal Sam Martinez said he didn't know about the H2S readings, or even why there was a monitoring station there. "I'm not aware of any problems with that gas in the area," he said. The school district has no records it was ever notified of elevated H2S levels by state officials, according to a spokesperson.

Some 800 feet from the school parking lot, a cluster of storage tanks and an injection well bear signs warning "Caution: Poison Gas."

I have students that I care about, that I love, and they breathe that air every day,
Lisa Rayburn, a fifth grade teacher in Fort Stockton

The environmental agency did not provide records indicating whether it conducted a follow-up investigation to determine the source of the gas affecting the school. TCEQ downplays violations of the state's limit, issuing memos stating that "adverse health effects would not be expected due to exposure to these concentrations."

"Odorous levels are not necessarily harmful levels," said Cann, the TCEQ spokesperson. Health effects related to the smell, she said, "should go away when the individual is no longer smelling the chemical."

The highest level recorded at the school was more than four times the state limit. But the agency claims that hydrogen sulfide has been shown to cause health effects only at levels 25 times the limit. It cites the findings of a limited 1990 study, though one of the paper's authors disavows that interpretation, telling The Examination that lower-level exposure can be hazardous. Academics call the agency's claim misleading, and a recent review of scientific research found health problems linked to very low levels of the gas.

Even the agency's own staff take a more cautious approach, evacuating when gas levels are much lower than what the agency claims is harmful.

Some residents looking to the agency for help say they've been let down. Lisa Rayburn, a fifth grade math teacher in Fort Stockton, said she experienced nausea and cramping when she was overcome by the rotten egg smell on a recent drive down a highway in the area. She said she hasn't received a response to her February complaint to TCEQ. The agency said it closed the complaint because there didn't appear to be a source of H2S that the agency would oversee in that area.



Lisa Rayburn, a fifth grade teacher in Fort Stockton, photographed on March 5, 2024. Rayburn said she felt sick from the rotten egg smell on a recent drive in the area.

Photo by Elizabeth Conley for the Houston Chronicle

Rayburn said she sometimes smells the gas at school and worries about her students.

“I have students that I care about, that I love, and they breathe that air every day,” she said.

Far from the Permian Basin, one school in particular weighed heavily on the mind of Birdwell, the former Railroad Commission official. In the North Central Texas town of Breckenridge, South Elementary School also butts up against a smattering of wells and tanks.

Turning down a little gravel road, Birdwell pointed to the school’s running track on one side and the stained tanks that he’d found venting H2S on the other side. “You don’t keep those buttoned up, and it can get pretty severe back up in here,” he said.

While at the commission, Birdwell patrolled with an infrared camera that showed otherwise-invisible plumes of methane, which leak out along with H2S. He visited regularly and found the tanks or an unlit flare venting hydrogen sulfide in six inspections from 2016 to 2019. “Gas was observed to be pluming toward the South Ward Elementary School play ground,” he wrote in one report. “Tracking right over the campus proper,” he stated in another.

Birdwell said he’d make operators repair the tanks, but it wouldn’t last: hydrogen sulfide would eat through seals “like crap through a goose.”

After Birdwell retired, other inspectors kept finding problems at the site, operated by a local company called Petex since late 2020. Four inspections in 2021 found multiple, persistent leaks and the Railroad Commission temporarily revoked Petex’s permission to operate there – though the company kept pumping even then, according to an inspection report.



A 2021 state investigation revealed leaking tanks near South Elementary School, in the North Central Texas town of Breckenridge.

Source: Railroad Commission of Texas

Local commission staff recommended “Appropriate Legal Penalty Action” against Petex for repeatedly failing to clean up an oil spill at the site. The company finally cleaned it up after that, so the commission declined to issue a penalty.

In 2022 and 2023, inspectors found Petex venting H2S there again. Each time, the company fixed it, at least temporarily.

Petex has another connection to the school: Its chief operating officer, Nic McClymond, whose family owns the business, is president of Breckenridge’s school board. McClymond didn’t respond to questions.

The company didn’t respond to detailed questions, but Petex production engineer Leo Medina said the company checks on the site each day. “You always worry about those things, but that’s part of the reason a pumper goes out there on a daily basis,” he said.

The school’s principal referred questions to the district’s then-superintendent, Bryan Allen, who declined to comment.

Driving through Breckenridge, wearing his old Railroad Commission hat, Birdwell passed dilapidated trailers and houses with peeling paint near the elementary school. “These folks can’t afford to just pick up and go somewhere else,” he said. He passed the “Boomtown Breckenridge” mural celebrating the area’s 1920s oil boom, and headed out to the ranches outside of town.

He pointed out violations in his no-nonsense way as he passed oil facilities: this gate should be locked, that flare is broken.

Out in the country, acres of dry dirt are crisscrossed by pipelines, pumping water into the ground and oil out of it.

Hydrogen sulfide wasn't a problem when Marka Giebler's ancestors built their Breckenridge ranches generations ago. Her great-grandfather gave land rights to oil producers in 1916 with an X as his signature, she said, and the family has been living next to oil wells ever since.

Decades later, oil companies began injecting water underground to push out the oil, leading over time to the spread of hydrogen sulfide. Giebler said H2S gives her headaches and rashes, and affects family members, too.

"It's very serious. I think it has affected all of our health," she said. "We've had oil companies that have told us, 'Just move.' We've been here generations. It's our place."

She and some family members have pushed back and filed complaints. But Giebler said they were scorned by relatives, friends and community members – many of whom get royalties from the oil or work in the industry. "My own family told me, 'Shut up, you're going to get everything closed down,'" Giebler said. "When you live in an area that's so dependent on an industry, it's so hard to get anyone to help."



Tom Brown contributed reporting. Special thanks to Tom Brown and the Fund for Investigative Journalism for prompting The Examination to investigate H2S in Texas.

L&R ENVIRONMENTAL LANDFARMS
Non-Municipal Solid Waste Profile Application for Soil Containing Petroleum Hydrocarbons

Date 8-18-15

GENERATOR: Alta Mesa Services To be billed? YES (NO)
ADDRESS: 15021 Katy Freeway Ste. 400
CITY: Houston STATE TX ZIP 77094
CONTACT PERSON Wade Moore TITLE Manager
GENERATOR PHONE # (832) 248-9390 FAX
TEL # FOR CONTACT SAME EMAIL wmoore@altamesa.net

Environmental Firm Handling Contract (If other than Generator):
NAME: H2O Environmental To be billed? (YES) NO
ADDRESS: 6679 S. Supply Way
CITY: Boise STATE ID ZIP 83716
CONTACT PERSON Joe Wickenden TITLE manager
TELEPHONE # (208) 602-8986 FAX EMAIL jwickenden@enucleanwp.com
OTHER INFO

PROFILE OF PETROLEUM HYDROCARBONS

CONTAMINATION SITE/SOURCE (IF UST FACILITY, PROVIDE STATE UST REGISTRATION #

Alta Mesa Services 434 Highway 30 South New Plymouth, ID 83665
Site Location – Name – Address

Crude Condensate
Source

GENERAL DESCRIPTION OF HYDROCARBON SOURCE: Crude condensate release

(If necessary, use page 2 for further description)

CONTAMINANT: DIESEL _____ GASOLINE _____ OTHER * Crude Condensate

* If OTHER, please explain

ESTIMATED QUANTITY TO TREAT (lbs\tons) 185 tons

PRICE PER TON AGREED UPON BY CLIENT AND L&REL: $_____/PER TON

Terms are net 30 days w/2% per month finance charge on past-due invoices and $300 minimum invoice unless otherwise noted and acknowledged below by a representative of L&R ENVIRONMENTAL LANDFARMS (LREL). Payables shall have added any legal & court costs should those payables be forced into collection(s). All invoices shall be payable to and business executed to and from L&R Environmental Landfarms. Home Office, PO Box 65 Kuna, ID 83634.

PLEASE ATTACH COPIES OF THE APPROPRIATE LABORATORY ANALYTICAL REPORTS AND ANY OTHER USEFUL INFORMATION TO CHARACTERIZE THE NON-HAZARDOUS SOIL CONTAINING PRTROLEUM HYDROCARBON AND THE HYDROCARBON SOURCE / SITE.

Signature of Generator or Authorized Environmental Contractor – Handler — *Date* 8-18-15

Joe Wickenden — *Print name of signature above*

Manager — *Title*

Signature of LREL Representative — *Date*

Print name of Representative above

NOTES:

THIS SOIL ORDER MUST ACCOMPANY A WASTE ACCEPTANCE CONTRACT AND A GENERATOR-SIGNED CRITERIA ORDER ACCEPTANCE FORM W/L&REL.

USE THIS SPACE FOR FURTHER DESCRIPTION NOTES:

GENERATOR CERTIFICATION

I shall hereby agree to the terms of this contract and certify and warrant that the solid waste described is not a hazardous waste and all information submitted on this form and all attached documents are true and accurate.

Signature: _____ Date: 8-18-15

Print Name above here Joe Wickenden Title: manager

Generator Name Alta Mesa Services

Generator Address 15021 Katy Freeway Ste. 400 Houston, TX 77094

SAMPLE TYPE CODE
S - Routine Sample
P - Repeat sample (at original tap)
E - Enforcement (chain of custody)
U - Upstream repeat
D - Downstream repeat
X -Other Repeat
W - Untreated
V - Invalidated by Lab
C - Construction / Special

ANALYTICAL LABORATORIES, INC.

ID00020
1804 N. 33rd Street
Boise, Idaho 83703
1-800-574-5773
1-208-342-5515
www.analyticallaboratories.com

Public Water Supply X Private Water Supply Other_____

NAME OF WATER SYSTEM	COUNTY	PWS

REPORT RESULTS TO:

JEFF JANIK
ALTA MESA SERVICES, LP
15021 KATY FREEWAY
SUITE 400
HOUSTON, TX 77094

DATE RECEIVED	3/21/2014
TIME RECEIVED	9:20
DATE ANALYZED	3/21/2014
TIME ANALYZED	13:45
IF RETEST, ORIGINAL SAMPLE DATE	
CHILLED 10 C	[X] YES [ ] NO

SEND ADDITIONAL COPIES TO:

e-mail: JJANIK@ALTAMESA.NET

Phone (713) 824-9427 Ext Fax

COLLECTED BY:

TRANSPORTED BY: JJ

SAMPLE TYPE	COLLECTION DATE/TIME	Sampling Location	Cl res	TOTAL COLIFORMS SM 9223	*E. COLI* SM 9223	HPC SM 9215
C	3/20/2014 16:00	LAB# 1410058 PROJECT: ML INV 2-10 ZONE 5 4288-4300		ABSENCE	ABSENCE	

REMARKS:

ANALYST: LM
DATE PRINTED: 3/25/2014

ANALYTICAL METHODS

Total Coliforms

SM 9222 Membrane Filter Technique, Parts 909 and 909A, Standard Methods...16th ed.,1985

SM 9221 Mutiple Tube Fermentation , Parts 908 and 908A, and 908B, Standard Methods... 16th

SM 9223 MMO-MUG Test Per 40 CFR141 21(f)(3)(IV)

E. coli

MUG Test Per 141.214(x)(7) and 40 CFR 141.21(f)(6)(III)

HPC

Pour Plate, Part 907, Standard Methods..., 16th ed., 1

Records shall be retained and destroyed in accordance with IDAPA 58.01.08 and 40 CFR 141.33. In general, records shall not be retained beyond prescribed retention times.

Analytical Laboratories, Inc.

Brian McGovern 3/25/2014
Laboratory Supervisor Date

Analytical Laboratories, Inc.

1804 N. 33rd Street
Boise, Idaho 83703
Phone (208) 342-5515

Attn: JEFF JANIK
ALTA MESA SERVICES, LP
15021 KATY FREEWAY
SUITE 400
HOUSTON, TX 77094

Collected By:
Submitted By: JJ

Source of Sample:
PROJECT: ML INV 2-10 ZONE 5 4288-4300

Time of Collection: 16:00
Date of Collection: 3/20/2014
Date Received: 3/21/2014
Report Date: 4/2/2014

Field Temp: **Temp Rcvd in Lab:** 7.1 °C
PWS: **PWS Name:**

Laboratory Analysis Report

Sample Number: 1410059

Methane, Ethane, and Ethene testing were performed by Accutest Mountain States (AMS).

Test Requested	MCL	Analysis Result	Units	MDL	Method	Date Completed	Analyst
Silica	UR	103	mg/L	0.25	EPA 200.7	3/24/2014	KC
Calcium, Ca	UR	31.3	mg/L	0.50	EPA 200.7	3/25/2014	KC
Sodium, Na	UR	449	mg/L	0.50	EPA 200.7	3/25/2014	KC
Potassium, K	UR	12.4	mg/L	0.5	EPA 200.7	3/25/2014	KC
Magnesium, Mg	UR	0.67	mg/L	0.50	EPA 200.7	3/25/2014	KC
Aluminum, Al	UR	4.03	mg/L	0.10	EPA 200.7	3/24/2014	KC
Arsenic Low	0.01	< 0.005	mg/L	0.005	EPA 200.8	4/1/2014	JH
Barium, Ba	2	5.33	mg/L	0.05	EPA 200.7	3/24/2014	KC
Boron, B		9.63	mg/L	0.10	EPA 200.7	3/24/2014	KC
Iron, Fe	UR	3.37	mg/L	0.05	EPA 200.7	3/24/2014	KC
Manganese, Mn	UR	0.08	mg/L	0.05	EPA 200.7	3/24/2014	KC
Uranium, U	30	< 5	ug/L	5	EPA 200.8	4/1/2014	JH
Chromium Low	0.1	0.019	mg/L	0.010	EPA 200.8	4/1/2014	JH
Lead Low	0.015	0.148	mg/L	0.010	EPA 200.8	4/1/2014	JH
Strontium, Sr		1.21	mg/L	0.01	EPA 200.7	3/24/2014	KC
Selenium Low	0.05	< 0.010	mg/L	0.010	EPA 200.8	4/1/2014	JH

MCL = Maximum Contamination Level
MDL = Method/Minimum Detection Limit
UR = Unregulated

Date Report Printed: 4/2/2014 2:41:05 PM

Laboratory Analysis Report

Sample Number: 1410059

Methane, Ethane, and Ethene testing were performed by Accutest Mountain States (AMS).

Test Requested	MCL	Analysis Result	Units	MDL	Method	Date Completed	Analyst
Nitrate (as N)	10	< 0.2	mg/L	0.2	EPA 300.0	3/21/2014	NC
Benzene		4280	ug/L	0.5	EPA 8260B	3/25/2014	CY
Toluene		4150	ug/L	0.5	EPA 8260B	3/25/2014	CY
Ethylbenzene		425	ug/L	0.5	EPA 8260B	3/25/2014	CY
Xylene, Total		2480	ug/L	0.5	EPA 8260B	3/25/2014	CY
Methane		2.29	mg/L	0.002	RSKSOP 175	3/31/2014	AMS
Ethane		0.521	mg/L	0.0008	RSKSOP 175	3/31/2014	AMS
Ethene		<0.0012	mg/L	0.0012	RSKSOP 175	3/31/2014	AMS
pH	UR	8.8	S.U.		SM 4500-H B	3/21/2014	JH
Conductivity	UR	1,960	umhos	2	SM 2510B	3/21/2014	JH
Turbidity		91.2	NTU	0.5	EPA 180.1	3/21/2014	JH
Chloride, Cl	UR	214	mg/L	1	EPA 300.0	3/23/2014	NC
Fluoride, F	4.0	10.2	mg/L	0.10	EPA 300.0	3/23/2014	NC

The fluoride value exceeds the EPA maximum contamination level of 4.0 mg/L.

Sulfate, SO4	UR	38	mg/L	1	EPA 300.0	3/23/2014	NC
Alkalinity	UR	424	mg/L CaCO3		EPA 310.1	3/28/2014	CJS
Hardness	UR	85.6	mg/L	5.0	SM 2340	3/28/2014	CJS
Oil and Grease		105	mg/L	5	EPA 1664	4/1/2014	RME
Total Dissolved Solids	UR	1,650	mg/L	25	SM 2540C	3/25/2014	DLR
Total Suspended Solids		57	mg/L	3	SM 2540 D	3/22/2014	DP
Surfactants	UR	<0.01	mg/L	.01	SM 5540	3/26/2014	MDM

MCL = Maximum Contamination Level
MDL = Method/Minimum Detection Limit
UR = Unregulated

Thank you for choosing Analytical Laboratories for your testing needs.
If you have any questions concerning this report,
please contact your client manager: **James Hibbs**

Date Report Printed: 4/2/2014 2:41:05 PM

Analytical Laboratories, Inc.

1804 N. 33rd Street
Boise, Idaho 83703
Phone (208) 342-5515

Date Report Printed: 4/8/2014 10:20:10
http://www.analyticallaboratories.com

Laboratory Analysis Report

Sample Number: 1410060

Attn: JEFF JANIK
ALTA MESA SERVICES, LP
15021 KATY FREEWAY
SUITE 400
HOUSTON, TX 77094

Collected By:
Submitted By: JJ

Source of Sample:
PROJECT: ML INV 2-10 ZONE 5 4288-4300

Time of Collection: 16:00
Date of Collection: 3/20/2014
Date Received: 3/21/2014
Report Date: 4/8/2014

PWS#:
PWS Name:

Field Temp: Temp Rcvd in Lab: 7.1 °C

Test Requested	MCL	Analysis Result	Units	MDL	Method	Date Completed	Analyst
Gross Alpha	15 pCi	<3	pCi/L	3	EPA 900.0	3/31/2014	SUM
Gross Beta		<4	pCi/L	4	EPA 900.0	3/31/2014	SUM

MCL = Maximum Contamination Level
MDL = Method/Minimum Detection Limit
UR = Unregulated

Thank you for choosing Analytical Laboratories for your testing needs.

If you have any questions about this report, or any future analytical needs, please contact your client manager:

James Hibbs

(L+R) 019248

Waste Profile

Alta Mesa Services
Company Name

Oily Water
Type Of Waste In Load

26.00
Weight in Tons

1
Number Of Jobs In Load

8326016
Job or Invoice Number

Job or Invoice Number

Job or Invoice Number

Job or Invoice Number

Job or Invoice Number

Job or Invoice Number

Weish In:
TruckID: 95
01:33 PM Wed Oct 17, 18
Inbound 48.07 ton

Weish Out:
Truck ID: 95
01:50 PM Wed Oct 17, 18

48.07 ton Gross
22.07 ton Tare
26.00 ton Net

To Weish Out Press
<F1> <95> <ENTER>

By signing, I agree to the best of my knowledge that the contents of this load does not contain any hazardous waste.

DUANE MADSEN

Duane Madsen
Transporter Signature

Environmental Landfarms
+ Responsible Waste Solutions +

NON-HAZARDOUS WASTE MANIFEST

Please print or type (Form designed for use on elite (12 pitch) typewriter)

NON-HAZARDOUS WASTE MANIFEST

1. Generator's US EPA ID No.

Manifest Document No. 832606

2. Page 1 of

3. Generator's Name and Mailing Address
ALTA MESA SERVICES
15021 KATE FREEWAY SITE 400
HOUSTON, TX 77094

TRK 95
TUR 165

4. Generator's Phone (281) 796-2727

5. Transporter 1 Company Name
L&R TRANSPORT MC#1981293-C DOT#2912146

6. US EPA ID Number

A. State Transorter's ID

B. Transporter 1 Phone 208-519-6010

7. Transporter 2 Company Name

8. US EPA ID Number

C. State Transporter's ID

D. Transporter 2 Phone

9. Designated Facility Name and Site Address
L&R ENVIRONMENTAL LAND FARMS
1100 W. THOMPSON ROAD
KUNA, ID 83634

10. US EPA ID Number

E. State Facility's ID

F. Facility's Phone

11. WASTE DESCRIPTION	12. Containers No.	12. Containers Type	13. Total Quantity	14. Unit Wt./Vol.
a. NON-HAZARDOUS, NON-REGULATED, INDUSTRIAL LIQUID WASTE PRODUCTION WATER OILY WATER	001	TT	6000	G
b.				
c.				
d.				

G. Additonal Descriptions for Materials Listed Above
PROFILE #L831640 (NON REGULATED LIQUID WASTER)

H. Handling Codes for Wastes Listed Above

15. Special Handling Instructions and Additional Information

NON-HAZARDOUS WASTE

GENERATOR

16. **GENERATOR'S CERTIFICATION:** I hereby certify that the contents of this shipment are fully and accurately described and are in all respects in proper condition for transport. The materials described on this manifest are not subject to federal hazardous waste regulations.

Printed/Typed Name | Signature | Date: Month 10 | Day 17 | Year 18

TRANSPORTER

17. Transporter 1 Acknowledgement of Receipt of Materials

Printed/Typed Name: DUANE MADSEN | Signature | Date: Month 10 | Day 17 | Year 18

18. Transporter 2 Acknowledgement of Receipt of Materials

Printed/Typed Name | Signature | Date: Month | Day | Year

FACILITY

19. Discrepancy Indication Space

20. Facility Owner or Operator; Certification of receipt of the waste materials covered by this maifest, except as noted in item 19.
L&R #019248 1 LOAD 26.00 TONS

Printed/Typed Name: Lisa Bushong | Signature: Lisa Bushong | Date: Month 10 | Day 17 | Year 18

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Rev. 3/95

(L+R) 019238

Waste Profile

Alta Mesa Services
Company Name

Waste Water
Type Of Waste In Load

31.60
Weight in Tons

1
Number Of Jobs In Load

8321635
Job or Invoice Number

Job or Invoice Number

Job or Invoice Number

Job or Invoice Number

Job or Invoice Number

Job or Invoice Number

Weigh In:
TruckID: 55
03:37 PM Tue Oct 16, 18
Inbound 49.01 ton

Weigh Out:
Truck ID: 55
03:53 PM Tue Oct 16, 18

49.01 ton Gross
17.41 ton Tare
31.60 ton Net

To Weigh Out Press
<F1> <55> <ENTER>

By signing, I agree to the best of my knowledge that the contents of this load does not contain any hazardous waste.

Transporter Signature
DAVID CALLAHAN

Environmental Landfarms
+ Responsible Waste Solutions +

NON-HAZARDOUS WASTE MANIFEST

Please print or type (Form designed for use on elite (12 pitch) typewriter)

NON-HAZARDOUS WASTE MANIFEST

1. Generator's US EPA ID No.

Manifest Document No. 832635

2. Page 1 of

3. Generator's Name and Mailing Address

ALTA MESA SERVICES
15021 KATE FREEWAY SITE 400
HOUSTON, TX 77094

55/185-2

4. Generator's Phone (281) 796-2727

5. Transporter 1 Company Name

L&R TRANSPORT MC#1981293-C DOT#2912146

6. US EPA ID Number

A. State Transorter's ID

B. Transporter 1 Phone 208-519-6010

7. Transporter 2 Company Name

8. US EPA ID Number

C. State Transporter's ID

D. Transporter 2 Phone

9. Designated Facility Name and Site Address

L&R ENVIRONMENTAL LAND FARMS
1100 W. THOMPSON ROAD
KUNA, ID 83634

10. US EPA ID Number

E. State Facility's ID

F. Facility's Phone

11. WASTE DESCRIPTION	12. Containers No.	12. Containers Type	13. Total Quantity	14. Unit Wt./Vol.
a. NON-HAZARDOUS, NON-REGULATED, INDUSTRIAL LIQUID WASTE PRODUCTION WATER	001	TT	7500	G
b.				
c.				
d.				

G. Additonal Descriptions for Materials Listed Above

PROFILE #L831640 (NON REGULATED LIQUID WASTER)

H. Handling Codes for Wastes Listed Above

15. Special Handling Instructions and Additional Information

GENERATOR

16. **GENERATOR'S CERTIFICATION:** I hereby certify that the contents of this shipment are fully and accurately described and are in all respects in proper condition for transport. The materials described on this manifest are not subject to federal hazardous waste regulations.

Printed/Typed Name | Signature | Date: Month Day Year

TRANSPORTER

17. Transporter 1 Acknowledgement of Receipt of Materials

Printed/Typed Name: DAVID R CALLAHAN | Signature | Date: Month 10 Day 16 Year 18

18. Transporter 2 Acknowledgement of Receipt of Materials

Printed/Typed Name | Signature | Date: Month Day Year

FACILITY

19. Discrepancy Indication Space

20. Facility Owner or Operator; Certification of receipt of the waste materials covered by this maifest, except as noted in item 19.

LTR #019238 1 LOAD 31.60 TONS

Printed/Typed Name: Lisa Bushong | Signature: Lisa Bushong | Date: Month 10 Day 16 Year 18

NON-HAZARDOUS WASTE

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Rev. 3/95

THE ARGUS OBSERVER

AG alerts Alta Mesa that it violated regulatory rules

Leslie Thompson The Argus Observer Apr 2, 2019 Updated Apr 2, 2019 1



Natural gas is flared from energy firm Alta Mesa's Fallon well site across the Payette River from the City of Fruitland water and wastewater facilities in March 2018.

Rob Ruth | The Argus Observer

PAYETTE COUNTY — The sole oil and gas producer in Idaho violated state regulatory rules on use of chemical fracturing, according to an administrative complaint and notice of violation filed by the Idaho Attorney General on behalf of the Idaho Department of Lands.

The complaint filed on Feb. 5, 2019 alleges that AM Idaho, also known as Alta Mesa, which has several natural gas wells in Payette County, violated Idaho Code by "treating a well" without the proper steps. This included not giving ample notice to or getting approval from Idaho Oil and Gas Commission and not obtaining a permit and paying applicable fees before performing the work.

According to the facts in the administrative complaint, Alta Mesa requested by email on July 9, 2018, the authorization to use acid treatment in the ML Investments No. 1-11 well. The email said the company was planning to pump an entire treatment into the well, which included 500 gallons of Xylene and 1,000 gallons of a mixture that contained 15 percent hydrofluoric acid. The plan was to perform the treatment by the end of the day the email was sent.

IDL officials, according to the complaint, responded within two hours citing Idaho Administrative Code stating "all well treatments require an application, fee and review," and did not approve the company's notice.

A request for a phone call by Alta Mesa followed the email, during which Alta Mesa stated it would resubmit the request, but did not say operations would proceed.

The following day, a revised work request from Alta Mesa was emailed to IDL stating “Objective: Suspect near well bore damage. Pump acid treatment to help dissolve possible skin damage near well bore and increase well deliverability.”

IDL requested more information, including a copy of the contractor’s proposed work program, to evaluate whether such a treatment would require a permit, according to the complaint.

Three days later, on July 13, 2018, Alta Mesa’s attorney by phone, and subsequently Alta Mesa by email, informed IDL that Alta Mesa had already proceeded with treating the well.

Alta Mesa was given a deadline of July 20, 2018 to get more information to IDL, including a final report from the contractor, which was only partially met on July 18. On July 20, IDL reiterated its request for additional information including “method and timeline for the management, storage and disposal of well treatment fluids, including the disposal site and plans for reuse, if any.” IDL gave Alta Mesa an additional week to get the information, and Alta Mesa responded within two days, again with partial information.

On Aug. 3, IDL sent a second request for the final report from the contractor, and asked a followup question “about how the range of frac gradients for the area was calculated.” IDL again gave Alta Mesa a week to respond, and the company responded early informing IDL that “its contractor did not do a post job report and there was no recording of the job digitally or by chart recorder.

“Instead, Alta Mesa monitored the analog pressure gauges and sight glasses throughout the job and recorded those numbers,” according to the complaint.

Alta Mesa did provide IDL its formula for calculating frac pressure.

Several questions the newspaper sent to Idaho Department of Lands won’t be answered until the end of this week, according to Mick Thomas, division administrator, Oil & Gas and secretary to the Oil & Gas Commission. These questions include whether IDL officials since knowing about the violation in July of 2018 have conducted, or instructed any outside agency to perform monitoring or testing of groundwater or nearby wells to see whether the hydroflouric acid or xylene is showing up elsewhere.

Also asked was whether IDL has knowledge that acid or other chemicals have been being put into other wells in Payette County.

The complaint gave AM Idaho 14 days to respond and request either an administrative hearing or an informal settlement meeting. Scott Graf, public information officer for the Idaho Attorney General office, said that while they don’t normally comment on pending actions or specific settlement discussions, that “a formal hearing has not been scheduled,” and no reply has yet come back from IDL about whether AM Idaho has responded to them regarding a settlement meeting.

Regardless of which hearing option Alta Mesa chooses, the alleged violations, according to the complaint, carry a proposed civil penalty of $20,000.

Citizens Allied for Integrity and Accountability, a watchdog group based in Eagle, alerted media to the Feb. 5 administrative complaint. The group’s President Shelley Brock responded to the news by saying, “This just confirms what industry representatives here have admitted from the start: that they would use whatever means necessary to produce those wells … What we find exceptionally disturbing is the fact that it has taken state regulators seven months to formally

charge Alta Mesa for violating the law, and that during that time these officials have continued to mislead the media and citizens about what is really happening here."

Brock was referring to the numerous concerns brought forth by citizens at multiple city council meetings and town halls regarding fracking.

IDL officials and Alta Mesa representatives have repeatedly told the community that Idaho's geology doesn't work for hydraulic fracturing — including Governor Brad Little in when he was still campaigning for his current seat during a televised public debate who said, "There is no fracking in Idaho."

While hydraulic fracturing, more commonly known as fracking might not be the method of extraction being used by Alta Mesa, chemical fracturing is the well treatment described in the administrative complaint.

According to records, this is the company's second administrative violation in the past four months, having been charged in October of 2018 for recompleting a gas well without proper protocol, including permits. In that instance, the state settled with AM Idaho for a fraction of the proposed penalties.

Alta Mesa is also the subject of a class action suit regarding nonpayment of royalties with citizens in Payette County, and several other similar class action suits across the United States.

Requests for comment from Alta Mesa were unreturned by press time.

Leslie Thompson is the editor at The Argus Observer. She can be reached at (541) 823-4818 or by emailing lesliet@argusobserver.com. To comment on this story, go to www.argusobserver.com.

Treating wells with acid

Acidizing refers to the stimulation of a reservoir formation by pumping a solution containing reactive acid to improve the permeability and enhance production of a well. In sandstone formations, the acids help enlarge the pores, while in carbonate formations, the acids dissolve the entire matrix. Acidizing can be divided into two categories:

• Matrix acidizing – mostly used in sandstone formations, acid is pumped into a well at low pressures, dissolving sediments and mud solids, increasing the permeability of the rock, enlarging the natural pores, and stimulating the flow of oil and gas.

• Fracture acidizing – mostly used in carbonate formations, involves pumping acid at higher pressures, but still lower than those used during fracking. The acids fracture the rock, allowing for the flow of oil and gas.

Acidizing usually occurs in aging wells that are in the final stages of production. It primarily uses hydrochloric and hydrofluoric acids at highly diluted concentrations, between 1 and 15 percent.

It is listed by the National Fire Protection Association in the most dangerous category of hazardous materials, and is recognized on the Superfund list as an "extremely hazardous substance." HF can cause severe burns to the skin and eyes, and can damage lungs in ways that are not immediately noticeable. If absorbed through the skin, even in minute amounts, and left untreated, it can cause death.

Source: Earthworks.org

LAWRENCE G. WASDEN
Attorney General
State of Idaho

DARRELL G. EARLY
Deputy Attorney General
Chief, Natural Resources Division

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Attorneys for Complainants

DEPT. OF LANDS
2019 FEB -5 PM 2:54
BOISE, IDAHO

BEFORE THE IDAHO OIL AND GAS CONSERVATION COMMISSION

In the Matter of:	)	Docket No. CC-2019-OGR-01-001
AM IDAHO, LLC. & ALTA MESA SERVICES, LP	)	ADMINISTRATIVE COMPLAINT & NOTICE OF VIOLATION
Respondent.	)	

This administrative complaint against AM Idaho, LLC and Alta Mesa Services, LP (collectively "Respondent" or "Alta Mesa") is filed on behalf of the Idaho Department of Lands' Oil and Gas Division ("IDL") with the Idaho Oil and Gas Conservation Commission ("Commission") pursuant to Idaho Code §§ 47-329 and 47-328(1) and (2). This complaint also serves as a notice of violation issued to Alta Mesa pursuant to Idaho Code § 47-329. As described below, IDL has identified certain alleged violations by Alta Mesa of Title 47, Chapter

3, Idaho Code, commonly known as the Oil and Gas Conservation Act, and the Rules Governing Conservation of Oil and Natural Gas in the State of Idaho, IDAPA 20.07.02.

JURISDICTION AND AUTHORITY

1. The Commission has jurisdiction and authority over all persons and property necessary to enforce the Oil and Gas Conservation Act ("Act"). Idaho Code § 47-314(8); Idaho Code § 47-315(1).
2. The Commission has authority to make and enforce rules, regulations, and orders, and do whatever may reasonably be necessary to carry out the provisions of the Act. Idaho Code § 47-314(8); Idaho Code § 47-315(1), (8).
3. Complainant IDL has "the power to exercise, under the general control and supervision of the commission, all of the rights, powers and duties vested by law in the commission, except those provided in sections 47-328 and 47-329(3)." Idaho Code § 47-314(7).

APPLICABLE LAWS AND REGULATIONS

4. Idaho Code § 47-316 provides:

> (1) It shall be unlawful to commence operations for the drilling or treating of a well for oil and gas without first giving notice to the commission of intention to drill or treat and without first obtaining a permit from the commission under such rules and regulations as may be reasonably prescribed by the commission and by paying to the commission a filing and service fee as provided by this section.
>
> (a) Any request for a permit or authorization as set forth in subsection (3)(a), (b), (c), (d), (e), (f), (g), (m), (n) or (o) of this section shall be made by application to the department of lands, and processed as provided in this section.
> ...
>
> (3) The department shall collect the following fees . . .
> ...
>
> (d) Application to treat a well, if separate from an application for a permit to drill a well.....1,000

5. IDAPA 20.07.02.30.01 provides:

Written Authorization Required. Any written notice of intention to do work or to change plans previously approved must be filed with the Department, unless otherwise directed, and must be approved before the work is begun. Such approval may be given orally and, if so given, shall thereafter be confirmed by the Department in writing. Written notices may be submitted to the Department by e-mail or facsimile.

6. A well treatment is defined as "Actions performed on a well to acidize, fracture, or stimulate the target reservoir." IDAPA 20.07.02.010.60.

7. IDAPA 20.07.02.210.01 provides in relevant part:

> Application Required. . . . Approval by the Department is required prior to the well treatments being implemented. Actions to clean the casing or perforations not in excess of pressures sufficient to overcome the fracture gradient in the surrounding formation are not considered to be well treatments, but operators must notify the Department when such actions occur.

8. IDAPA 20.07.02.210.01 requires an operator to submit certain listed information in any application for well treatment.

9. IDAPA 20.07.02.210.06 details reporting requirements for well treatments. A well treatment report must be submitted within thirty (30) days of the treatment and must include the information listed in IDAPA 20.07.02.210.06(a)-(h).

10. Idaho Code § 47-329(3) provides:

> Any person who violates or fails to comply with any of the provisions of this chapter or any rules or orders made or promulgated hereunder may be assessed a civil penalty by the commission or its duly authorized agent of not more than ten thousand dollars ($10,000) for each violation and shall be liable for reasonable attorney's fees. Each day the violation continues shall constitute a separate and additional violation, punishable by separate and additional civil penalties in like amount or other like civil penalties as determined by the commission; provided that the civil penalties do not begin to accrue until the date notice of violation and opportunity to be heard are given.
>
> (a) Assessment of a civil penalty may be made in conjunction with any other commission administrative action.
>
> (b) No civil penalty may be assessed unless the person charged was given notice and opportunity for a hearing pursuant to chapter 52, title 67, Idaho Code, which

civil penalty begins to accrue no earlier than the date notice of violation and opportunity for a hearing are given.

(c) If the commission is unable to collect such penalty or if any person fails to pay all or a set portion of the civil penalty as determined by the commission, it may recover such amount by action in the appropriate district court.

(d) Any person against whom the commission has assessed a civil penalty under the provisions of this section may, within twenty-eight (28) days of the final action by the agency making the assessment, appeal the assessment to the district court of the county in which the violation is alleged by the commission to have occurred pursuant to chapter 52, title 67, Idaho Code.

(e) All civil penalties collected pursuant to this section shall be remitted to the oil and gas conservation fund.

FACTS

11. IDL granted Alta Mesa an amended permit to drill a gas well named the ML Investments #1-11 on September 22, 2014. The ML Investments #1-11 well is located in a 640 acre spacing unit composed of Section 11, Township 8N, Range 4W, Boise Meridian, Payette County, Idaho, located in the Willow Field.

12. Alta Mesa is the current operator of the ML Investments #1-11.

13. Alta Mesa completed the ML Investments #1-11 well on October 17, 2014. A well completion report named the Lower Target, or "LT," producing interval as 4278-84' Measured Depth (MD). A well completion report named the Upper Target, or "UT," producing interval as 4175-85' MD.

14. On July 9, 2018, Alta Mesa submitted by e-mail a sundry notice for an acid treatment on the ML Investments #1-11 well. Alta Mesa's sundry notice checked the "acidize" box for the "type of action." In its description of the operation, Alta Mesa stated:

> Attempt to pump entire treatment at 0.25 – 0.5 BPM rate
> 500 gal Xylene (11.9 bbls)
> 1000 gal (23.8 bbls) 15% HCL w/ 1.0% corr inhibitor and 2.0% iron control 0.5% clay-stay w/ 0.5% surfactant

Displace acid with 28 bbls 2% KCL water
18 bbls to displace acid to formation
10 bbls over displacement

We plan to begin this afternoon, July 9, 2018.

Alta Mesa's employee stated in the e-mail accompanying the sundry that "[w]e would like to begin this afternoon if you can get this approved for me."

15. IDL responded to Alta Mesa by e-mail within two hours. IDL cited IDAPA 20.07.02.210 and informed Alta Mesa that all well treatments require an application, fee, and review. IDL did not approve Alta Mesa's sundry notice.

16. After IDL's e-mail, Alta Mesa requested a phone call. Alta Mesa informed IDL that Alta Mesa would resubmit the sundry. Alta Mesa did not inform IDL that operations would proceed.

17. On July 10, 2018, Alta Mesa submitted by e-mail a revised sundry notice. The revised sundry added the following language:

> Objective: Suspect near well bore damage. Pump acid treatment to help dissolve possible skin damage near well bore and increase well deliverability.

IDL e-mailed Alta Mesa and requested additional information, including a copy of the contractor's proposed work program, to evaluate whether the proposed operation was a well treatment that would require a permit under IDAPA 20.07.02.210.

18. On July 13, 2018, Alta Mesa's attorney informed IDL by phone that Alta Mesa had already proceeded with the well treatment. That same day, IDL sent an e-mail to Alta Mesa informing Alta Mesa that IDL had learned that Alta Mesa had proceeded with the proposed well treatment for the ML Investments #1-11 well without IDL's authorization. IDL also informed Alta Mesa that IDL had not received the information requested in IDL's July 10, 2018 e-mail; IDL then requested the same information for a second time. IDL also requested

a copy of the final report from the contractor detailing the operations performed during the entire operation. IDL gave Alta Mesa a deadline of Friday July 20, 2018 to submit these documents.

19. On July 18, 2018, IDL received an e-mail with several of the requested documents attached, including daily operations reports from July 10, 2018 to July 14, 2018 describing the well treatment that was conducted.

20. On July 20, 2018, IDL reiterated to Alta Mesa its request for additional information regarding "the method and timeline for the management, storage and disposal of well treatment fluids, including the disposal site and plans for reuse, if any" and informed Alta Mesa that the documents Alta Mesa had already provided did not appear to contain the requested information. IDL gave Alta Mesa a July 27, 2018 deadline to provide the information. Alta Mesa responded on July 20, 2018 with an e-mail summary of who provided the fluids, how the fluids arrived and were stored, and their disposal.

21. On August 3, 2018, IDL sent Alta Mesa a second e-mail request for "the final report from the contractor detailing the operations performed during the entire operation." IDL also asked a follow up question about how the range of frac gradients for the area was calculated. IDL gave Alta Mesa an August 10, 2018 deadline to submit that information to IDL.

22. Alta Mesa responded with an August 7, 2018 e-mail informing IDL that its contractor did not do a post job report and there was no recording of the job digitally or by chart recorder. Instead, Alta Mesa monitored the analog pressure gauges and sight glasses throughout the job and recorded those numbers. Alta Mesa also provided its formula for calculating frac pressure and its employee's July 9, 2018 summary notes of the operation. Alta Mesa additionally submitted a Safe to Perform (STP) Report form that its contractor completed

prior to starting work. The STP form indicated that it was filled out on July 9, 2018 at 7am MT.

ALLEGED VIOLATIONS

Violation One: Violation of Idaho Code § 47-316(1)(a), IDAPA 20.07.02.030, IDAPA 20.07.02.210.01

Proposed Civil Penalty Amount: $10,000

Alta Mesa violated Idaho Code § 47-316(1)(a), IDAPA 20.07.02.030, and IDAPA 20.07.02.210.01, by performing a well treatment before applying for or obtaining IDL approval. Alta Mesa performed a well treatment because the operation in question was an action to acidize the target reservoir. While IDAPA 20.07.02.210.01 provides that well treatments are not "[a]ctions to clean the casing or perforations not in excess of pressures sufficient to overcome the fracture gradient in the surrounding formations," in this case the operation was to acidize the target reservoir and to clean the formation, not an action to clean the casing or perforations.

Alta Mesa's own sundry notice stated that Alta Mesa's objective was to "[p]ump acid treatment to help dissolve possible skin damage near well bore and increase well deliverability." Therefore, Alta Mesa performed a well treatment that required an application to IDL and approval from IDL.

Alta Mesa did not get IDL approval before performing the work. Alta Mesa's records indicate that work on the job to acidize the ML Investments #1-11 well began on July 9, 2018. On July 9, 2018, IDL cautioned Alta Mesa to review IDAPA 20.07.02.210 regarding well treatments and informed Alta Mesa that an application was needed to perform a well treatment. Alta Mesa submitted a revised sundry notice on July 10, 2018, but did not tell IDL in the sundry notice or in its correspondence that it had already performed or was currently

performing the work at issue. On July 13, 2018, Alta Mesa's attorney informed IDL that the well treatment work had already taken place. Alta Mesa was required to apply for a well treatment and obtain IDL approval before Alta Mesa performed its well treatment work. Alta Mesa failed to do so. Thus, IDL alleges Alta Mesa violated Idaho Code § 47-316(1)(a), IDAPA 20.07.02.030, and IDAPA 20.07.02.210.01.

Violation Two: Violation of IDAPA 20.07.02.210.06

Proposed Civil Penalty Amount: $10,000

Alta Mesa violated IDAPA 20.07.02.210.06 by failing to submit a report on well treatment with the required items. A report on well treatment must be submitted within thirty (30) days of the treatment and must include the items listed in IDAPA 20.07.02.210.06(a)-(h). Thirty days have passed since the work was performed. Alta Mesa has not as of this date filed a report on well treatment that contains the following items: IDAPA 20.07.02.210.06(a) (the daily production of oil, gas, and water both prior to and after the operation); and IDAPA 20.07.02.210.06(d) (documentation demonstrating the chemicals used were reported to a www.fracfocus.org or another publicly accessible database approved by the Department). Thus, IDL alleges Alta Mesa violated IDAPA 20.07.02.210.06.

Total Proposed Civil Penalty: $20,000

REQUEST FOR RELIEF

As a result of the violations alleged above, IDL requests the following relief:

A. Order Alta Mesa to file an application, seek IDL approval, and submit all items in the required report on well treatment for the operations that have already occurred. The application shall include the fee required in Idaho Code § 47-316(3), follow the

process in Idaho Code § 47-316(1), and the application and reporting shall contain all of the requirements and follow the processes required in the Idaho Rules Governing Conservation of Oil and Natural Gas in the State of Idaho, including IDAPA 20.07.02.030 and IDAPA 20.07.02.210.

B. Award civil penalties of $20,000 to IDL that IDL shall remit to the Oil and Gas Conservation Fund pursuant to Idaho Code § 47-329(3)(e).

C. Award IDL reasonable attorney fees pursuant to Idaho Code § 47-329(3).

OPPORTUNITY TO RESPOND

This complaint also serves as a notice to Alta Mesa of its violations and notice of Alta Mesa's opportunity for a hearing as provided in Idaho Code § 47-329. Because the Department has filed this Notice of Violation with the Commission as an administrative complaint, Alta Mesa has the right to proceed directly to a formal administrative hearing before the Commission under the Idaho Administrative Procedure Act, Title 67, Chapter 52, Idaho Code. Alternatively, the Idaho Rules of Administrative Procedure of the Attorney General at IDAPA 04.11.01 encourage the use of informal proceedings, also known as settlement conferences, to settle contested cases.

If Alta Mesa decides to resolve this matter without proceeding directly to an administrative hearing, Alta Mesa can request a settlement meeting at IDL's Boise office. A request for an informal settlement meeting must be made via phone or e-mail within fourteen (14) days of receipt of this Complaint and Notice of Violation. Please contact Kristina Fugate, Deputy Attorney General, to schedule an informal settlement meeting at (208) 334-2400 or kristina.fugate@ag.idaho.gov.

The following IDL Oil and Gas Division representatives may be in attendance at the settlement meeting: Administrator, Program Manager, and Deputy Attorney General. At the settlement meeting, IDL will review the facts of this case, including any information and explanation Alta Mesa may wish to provide.

If Alta Mesa decides to forego the informal settlement meeting and request a formal administrative hearing before the Idaho Oil and Gas Conservation Commission, Alta Mesa must submit that request in writing by e-mail or letter within fourteen (14) days of receipt of this Notice of Violation. Please address requests for an administrative hearing to: Mick Thomas, Secretary to the Idaho Oil and Gas Conservation Commission at 300 N. 6th St, Suite 103, Boise, ID 83720 or mthomas@idl.idaho.gov. A failure to request an informal settlement meeting or to request a formal administrative hearing will result in IDL proceeding to a formal hearing before the Commission pursuant to Idaho Code §§ 47-328 and 47-329.

DATED this 5th day of February, 2019.

Kristina Fugate

KRISTINA N. FUGATE
Deputy Attorney General

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 5th day of February, 2019, a true and correct copy of the foregoing document was served on the following individual(s) by the method indicated:

AM Idaho, LLC &
Alta Mesa Services, LP
c/o Michael Christian
Marcus, Christian, Hardee & Davies, LLP
737 North 7th Street
Boise ID 83702-5595

[X] Certified Mail, Return Receipt Requested
[X] U.S. Mail
[ ] Overnight Delivery
[ ] Messenger Delivery
[ ] Email: MChristian@mch-lawyer.com

KRISTINA N. FUGATE
Deputy Attorney General

BEFORE THE IDAHO OIL AND GAS CONSERVATION COMMISSION

In the Matter of:	)	Docket No. CC-2019-OGR-01-001
AM IDAHO, LLC & ALTA MESA SERVICES, LP.	)	SETTLEMENT AGREEMENT AND CONSENT ORDER
Respondent.	)	

1. The Idaho Department of Lands' Oil and Gas Division ("IDL"), and Alta Mesa Services, LP and AM Idaho, LLC (collectively "Alta Mesa"), voluntarily enter into this settlement agreement and consent order ("SACO") pursuant to the Idaho Oil and Gas Conservation Act ("the Act"), Title 47, Chapter 3, Idaho Code; the Idaho Rules Governing Conservation of Oil and Gas in Idaho, IDAPA 20.07.02; the Idaho Administrative Procedure Act, Title 67, Chapter 53, Idaho Code; and the Idaho Rules of Administrative Procedure of the Attorney General, IDAPA 04.11.01. IDL and Alta Mesa may be collectively referred to as the "Parties."

2. Alta Mesa is the current operator of the ML Investments 1-11 well in Payette County, Idaho. On July 9, 2018 Alta Mesa sent a sundry notice to IDL that stated its intention to do an acid treatment on the ML Investments 1-11 well. Alta Mesa submitted an amended sundry notice on July 10, 2018 to clarify that the treatment was "to help dissolve possible skin damage near well bore and increase well deliverability." On July 13, Alta Mesa's attorney informed IDL that Alta Mesa had already proceeded with the well treatment. IDL did not receive and did not approve any application for well treatment.

3. On February 5, 2019, IDL filed an Administrative Complaint and Notice of Violation ("Administrative Complaint") alleging two violations against Alta Mesa. The February 5, 2019 Administrative Complaint is incorporated into the SACO by reference.

4. IDL provided Alta Mesa with the opportunity for a compliance conference and settlement meeting to discuss the Administrative Complaint's alleged violations and entry into a settlement agreement. On February 28, 2019, the settlement meeting was held.

5. Alta Mesa agrees to this SACO and the following terms:

    a. As to the Administrative Complaint's Violation One, Alta Mesa admits it violated Idaho Code § 47-316(1)(a), IDAPA 20.07.02.030, and IDAPA 20.07.02.210.01 when Alta Mesa performed a well treatment before obtaining IDL approval. Under Idaho Code § 47-316(1)(a), IDAPA 20.07.02.030, and IDAPA 20.07.02.210.01 Alta Mesa was required to obtain IDL approval before Alta Mesa performed that treatment, and Alta Mesa failed to do so.

b. As to the Administrative Complaint's Violation Two, Alta Mesa admits it violated IDAPA 20.07.02.210.06 by failing to timely submit a complete report on well treatment.

c. Alta Mesa agrees to apply for the well treatment it performed as required by the Act and the Idaho Rules Governing Conservation of Oil and Gas in Idaho, IDAPA 20.07.02, which includes:

   i. Paying IDL the $1,000 application fee (*See* Idaho Code § 47-316(3)(d)); and
   ii. Submitting to IDL the information required in IDAPA 20.07.02.210.

d. Alta Mesa agrees to submit the information required for a well treatment report within thirty (30) days of filing a complete well treatment application. This report shall include all the information required in IDAPA 20.07.02.210.06.

e. Alta Mesa shall pay IDL civil penalties in the following amounts:
   i. Five thousand dollars ($5,000) for the Administrative Complaint's Violation One.
   ii. Three thousand dollars ($3,000) for the Administrative Complaint's Violation Two.

f. Payment of civil penalties for Violation One and Violation Two shall be made no later than thirty (30) days after the Commission approves this SACO.

6. Payments shall be made payable to the Idaho Department of Lands and submitted to:

   Oil and Gas Division
   Idaho Department of Lands
   300 N. 6th St, Suite 103
   Boise, ID 83720

7. IDL shall deposit these payments into the Oil and Gas Conservation Fund.

8. This SACO shall not in any way relieve Alta Mesa from its obligation to comply with Title 47, Chapter 3, Idaho Code; the Idaho Rules Governing Conservation of Oil and Gas in Idaho, IDAPA 20.07.02, or other applicable local, state, or federal law.

9. This SACO shall bind Alta Mesa and its successors and assigns. Any change in ownership or corporate status of Alta Mesa, including, but not limited to, any transfer of assets or real or personal property shall not alter Alta Mesa's obligation to comply with the SACO's requirements, or to ensure compliance by any of Alta Mesa's successors or assignees, regardless of whether Alta Mesa continues to exist after any such transaction.

10. The provisions of this SACO are severable. If any provision of this SACO or part thereof is declared unenforceable or invalid, it shall not affect the validity or enforceability of the remaining provisions of this SACO.

11. Alta Mesa expressly recognizes that failure to comply with the terms of this SACO may result in a district court action for collection of civil penalties and other relief available under Idaho Code § 47-329.

12. This SACO contains the entire agreement between the Parties. This SACO may not be enlarged, modified, or altered without written consent of both Parties.

13. Any Party's facsimile signature to the SACO and any e-mailed copy of a Party's signature to this SACO, if received from the party or its legal counsel, will be deemed an original and binding signature of this SACO by the Party.

14. Each Party represents and warrants that it has the authority to enter into this SACO and to take all actions provided for herein. The effective date of this SACO shall be the date the IDL Oil and Gas Administrator signs the agreement. However, the SACO does not become enforceable until the Oil and Gas Conservation Commission ("Commission") issues an order accepting the SACO. If the Commission does not accept the SACO, this SACO becomes null and void.

15. The Parties agree that this SACO will be presented to the Commission and reviewed by the Commission under IDAPA 04.11.01.612. The Parties both carry the burden of showing the Commission that the settlement is in accordance with the law. IDAPA 04.11.01.613.

Dated this 3 day of April, 2019

Scott Ricks, CEO
Alta Mesa Services, LP & AM Idaho, LLC

Dated this 4 day of April, 2019

Richard "Mick" Thomas, Oil and Gas Division Administrator
Idaho Department of Lands

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Water Supply Determination Letters

The following list identifies cases where DEP determined that a private water supply was impacted by oil and gas activities. The oil and gas activities referenced in the list below include operations associated with both conventional and unconventional drilling activities that either resulted in a water diminution event or an increase in constituents above background conditions. This list is intended to identify historic water supply impacts and does not necessarily represent ongoing impacts. Many of the water supply complaints listed below have either returned to background conditions, have been mitigated through the installation of water treatment controls or have been addressed through the replacement of the original water supply. This list is dynamic in nature and will be updated to reflect new water supply impacts as they are reported to DEP and a determination is made; however, the list will retain cases of water supply impacts even after the impact has been resolved.

A redacted copy of the water supply determination letter/order can be viewed by clicking on the "Complaint #" or "ORDER" cell in the table. Each row on the list represents a single water supply determination. A single water supply determination may be represented by multiple "Complaint #s" (i.e., when more than one Complaint # is included in the same row) and, conversely, separate water supplies may be identified using the same "Complaint #" (i.e., when multiple rows list the same Complaint #). The list also identifies the municipality and county where each water supply is located along with the date of the water supply determination letter or the date the order was issued.

	DOGO	Complaint #	County	Twp/Boro	Date Letter Sent
1	East	ORDER	Susquehanna	Dimock	2/8/2019
2	East	ORDER	Susquehanna	Dimock	12/15/2010
3	East	ORDER	Susquehanna	Dimock	2/8/2019
4	East	ORDER	Susquehanna	Dimock	12/15/2010
5	East	ORDER	Susquehanna	Dimock	12/15/2010
6	East	ORDER	Susquehanna	Dimock	12/15/2010
7	East	ORDER	Susquehanna	Dimock	12/15/2010
8	East	ORDER	Susquehanna	Dimock	2/8/2019
9	East	ORDER	Susquehanna	Dimock	12/15/2010
10	East	ORDER	Susquehanna	Dimock	2/8/2019
11	East	ORDER	Susquehanna	Dimock	12/15/2010
12	East	ORDER	Susquehanna	Dimock	12/15/2010
13	East	ORDER	Susquehanna	Dimock	12/15/2010
14	East	ORDER	Susquehanna	Dimock	12/15/2010
15	East	ORDER	Susquehanna	Dimock	2/8/2019
16	East	ORDER	Susquehanna	Dimock	2/8/2019
17	East	ORDER	Susquehanna	Dimock	12/15/2010
18	East	ORDER	Susquehanna	Dimock	12/15/2010
19	East	258482	Susquehanna	Dimock	01/01/2009
20	East	258959	Susquehanna	Lenox Twp	5/27/2009

21	East	258960	Susquehanna	Lenox Twp	5/27/2009
22	East	259175	Tioga	Clymer	11/12/2008
23	East	260999	Tioga	Clymer	4/28/2009
24	East	260999	Tioga	Clymer	4/28/2009
25	East	260999	Tioga	Clymer	4/28/2009
26	East	263337	Susquehanna	Springville	9/9/2009
27	East	263337	Susquehanna	Springville	9/9/2009
28	East	263337	Susquehanna	Springville	9/9/2009
29	East	265150	Lycoming	McNett	12/4/2009
30	East	265150	Lycoming	McNett	12/4/2009
31	East	268097	Susquehanna	Rush	4/23/2010
32	East	269945	Bradford	Terry	2/7/2011
33	East	272059	Bradford	West Burlington	9/16/2010
34	East	272604	Bradford	Granville	9/2/2010
35	East	273310	Bradford	Terry	10/1/2010
36	East	273310	Bradford	Terry	10/1/2010
37	East	273310	Bradford	Terry	10/1/2010
38	East	273350	Bradford	Terry	12/19/2017
39	East	273403	Bradford	Terry	1/19/2017
40	East	273463	Wyoming	Washington	4/8/2011
41	East	273868	Bradford	Orwell	8/22/2011
42	East	274088 274465	Bradford	Tuscarora	3/25/2011
43	East	274348	Bradford	Tuscarora	3/7/2011
44	East	274484	Bradford	Wilmot	11/10/2010
45	East	274484	Bradford	Wilmot	11/10/2010
46	East	274484	Bradford	Wilmot	11/17/2010
47	East	274484	Bradford	Wilmot	11/10/2010
48	East	274484	Bradford	Wilmot	11/10/2010
49	East	274484	Bradford	Wilmot	11/10/2010
50	East	274484	Bradford	Wilmot	11/10/2010
51	East	274977	Bradford	Alba Boro	12/6/2010
52	East	275203	Bradford	Alba Boro	1/3/2011
53	East	275203	Bradford	Alba Boro	1/3/2001
54	East	275524 285034	Potter	Bingham	4/20/2011
55	East	275545	Potter	Bingham	4/20/2011
56	East	275833	Bradford	Monroe	12/3/2010
57	East	275834	Bradford	Monroe	12/3/2010
58	East	275834	Bradford	Monroe	12/3/2010
59	East	275992	Bradford	Alba Boro	12/6/2010
60	East	276069	Bradford	Terry	7/17/2017
61	East	276819	Bradford	Alba Boro	1/31/2011
62	East	277315	Bradford	West Burlington	6/18/2012
63	East	277726	Bradford	Troy	8/17/2011
64	East	277775	Bradford	Wyalusing	10/24/2011
65	East	277902	Bradford	West Burlington	6/18/2012
66	East	277927	Bradford	Wyalusing	10/24/2011
67	East	278614	Tioga	Charleston	5/4/2011

68	East	279070	Bradford	Wilmot	11/10/2020
69	East	279442	Potter	Allegheny	7/14/2011
70	East	279657	Wyoming	Meshoppen Twp	7/13/2011
71	East	279838	Lycoming	Franklin Twp	8/2/2011
72	East	280019	Lycoming	Franklin Twp	8/2/2011
73	East	280020	Lycoming	Moreland	3/8/2012
74	East	280023	Lycoming	Moreland	11/26/2013
75	East	280200	Bradford	Smithfield	8/1/2011
76	East	280207	Bradford	Stevens	2/20/2014
77	East	280209	Bradford	Stevens	2/20/2014
78	East	280219	Lycoming	Moreland	11/4/2011
79	East	280698	Bradford	Orwell	11/7/2011
80	East	281057	Tioga	Putnam	9/13/2017
81	East	282014	Tioga	Covington	11/1/2011
82	East	282304	Lycoming	Moreland	11/4/2011
83	East	282431	Susquehanna	Lenox Twp	9/21/2011
84	East	284149	Clinton	Grugan	1/17/2012
85	East	284589	Susquehanna	Rush	11/7/2011
86	East	285804	Bradford	Asylum	1/6/2012
87	East	286295	Lycoming	Moreland	9/5/2012
88	East	286302	Wyoming	Nicholson	1/11/2022
89	East	286302	Wyoming	Nicholson	1/11/2022
90	East	286490	Lycoming	Moreland	9/5/2012
91	East	286491	Lycoming	Moreland	9/5/2012
92	East	286551	Bradford	Wysox	8/28/2013
93	East	286642	Bradford	West Burlington	6/18/2012
94	East	286643	Bradford	West Burlington	6/18/2012
95	East	286658	Lycoming	Moreland	4/22/2013
96	East	287005	Tioga	Delmar	4/24/2019
97	East	287060	Tioga	Delmar	8/26/2019
98	East	287198	Sullivan	Elkland	9/9/2013
99	East	287445	Tioga	Delmar	10/25/2017
100	East	287981	Lycoming	Moreland	12/19/2017
101	East	288376	Tioga	Shippen	11/26/2013
102	East	289029	Susquehanna	Dimock	9/21/2011
103	East	289614	Clearfield	Gulich	8/24/2012
104	East	289642	Bradford	Leroy	8/13/2012
105	East	290009	Bradford	Leroy	8/13/2012
106	East	290279	Bradford	Leroy	8/13/2012
107	East	290453	Susquehanna	Lenox Twp	9/11/2012
108	East	291156	Bradford	Leroy	8/13/2012
109	East	291551	Sullivan	Forks	9/11/2013
110	East	291551	Sullivan	Forks	9/9/2013
111	East	291602	Tioga	Union	10/29/2018
112	East	291603	Tioga	Union	10/29/2018
113	East	291931	Susquehanna	Bridgewater	5/22/2015
114	East	292425	Susquehanna	Jessup	11/20/2018

115	East	292459	Sullivan	Forks	9/9/2013
116	East	292761	Bradford	Armenia	4/12/2013
117	East	292819	Bradford	Burlington	2/21/2013
118	East	293040	Tioga	Putnam	9/13/2017
119	East	293067	Lycoming	Moreland	4/22/2013
120	East	293075	Bradford	Springfield Twp	8/4/2014
121	East	293597	Bradford	Springfield Twp	8/4/2014
122	East	293929	Bradford	Warren	5/6/2014
123	East	294115	Bradford	Wilmot	5/22/2015
124	East	294619	Susquehanna	Dimock	10/22/2013
125	East	294741	Sullivan	Forks	9/9/2013
126	East	295774	Wyoming	Washington	8/28/2013
127	East	296362	Bradford	Franklin Twp	3/3/2015
128	East	297823	Susquehanna	Lenox Twp	10/11/2011
129	East	297824	Susquehanna	Lenox Twp	11/7/2011
130	East	297825	Susquehanna	Lenox Twp	3/2/2012
131	East	298064	Bradford	Springfield Twp	8/4/2014
132	East	300692	Bradford	Wysox	11/13/2014
133	East	301074	Susquehanna	Dimock	10/28/2014
134	East	301998	Susquehanna	Springville	8/4/2015
135	East	303492	Susquehanna	Dimock	2/21/2018
136	East	303704	Susquehanna	Springville	2/21/2018
137	East	306750	Susquehanna	Dimock	12/5/2014
138	East	308257	Lycoming	Wolf	1/31/2019
139	East	308296	Bradford	Springfield Twp	8/13/2015
140	East	308376	Susquehanna	Bridgewater	12/29/2014
141	East	308529	Lycoming	Eldred	12/12/2014
142	East	308755	Susquehanna	Hartford	11/21/2014
143	East	308786	Bradford	Herrick	2/11/2015
144	East	308946	Sullivan	Cherry	2/11/2016
145	East	309245	Wyoming	Windham	1/16/2015
146	East	309261	Lycoming	Eldred	2/2/2015
147	East	309747	Wyoming	Windham	5/19/2016
148	East	310458	Susquehanna	Hartford	5/19/2015
149	East	310486	Wyoming	Washington	6/4/2015
150	East	311069	Lycoming	Eldred	6/4/2015
151	East	311211	Lycoming	Wolf	1/31/2019
152	East	311274	Lycoming	Penn	1/31/2019
153	East	311436	Lycoming	Penn	1/31/2019
154	East	312409	Suilivan	Fox	7/10/2015
155	East	313289	Clinton	Gallagher	6/1/2022
156	East	314809	Lycoming	Moreland	1/31/2019
157	East	314825	Lycoming	Moreland	1/31/2019
158	East	315196	Potter	Sweden	10/27/2015
159	East	315269	Potter	Eulalia	12/14/2015
160	East	315271	Potter	Eulalia	12/14/2015
161	East	315272	Potter	Sweden	10/27/2015

162	East	315337	Potter	Eulalia	12/14/2015
163	East	315387	Potter	Sweden	12/14/2015
164	East	315646	Clinton	Chapman	8/9/2016
165	East	315738	Sullivan	Fox	11/13/2015
166	East	324291	Bradford	Wilmot	6/22/2017
167	East	325361	Susquehanna	Auburn Twp	4/3/2017
168	East	326085	Tioga	Putnam	9/13/2017
169	East	326420	Lycoming	Hepburn	3/12/2018
170	East	327047	Tioga	Bloss	9/22/2017
171	East	327326	Susquehanna	Auburn Twp	9/29/2017
172	East	327599	Susquehanna	Jackson	12/27/2017
173	East	327922	Susquehanna	Hartford	10/16/2017
174	East	328143	Bradford	Orwell	1/15/2021
175	East	329222	Susquehanna	Brooklyn	10/24/2017
176	East	329389	Susquehanna	Hartford	2/12/2020
177	East	329783	Lycoming	Wolf	1/31/2019
178	East	330215	Wyoming	Windham	7/24/2018
179	East	330216	Wyoming	Windham	7/24/2018
180	East	330217	Wyoming	Windham	7/24/2018
181	East	330225	Wyoming	Windham	7/24/2018
182	East	330739	Susquehanna	Silver Lake	2/21/2018
183	East	330982	Susquehanna	Hartford	6/1/2018
184	East	331773	Bradford	Ridgebury	12/10/2018
185	East	331774	Bradford	Ridgebury	12/10/2018
186	East	331945	Bradford	Ridgebury	12/10/2018
187	East	332016	Bradford	Ridgebury	12/10/2018
188	East	333470	Bradford	Ridgebury	12/10/2018
189	East	334115	Tioga	Gaines	1/22/2020
190	East	334513	Bradford	Wilmot	7/10/2018
191	East	335083	Tioga	Liberty	8/3/2018
192	East	335085	Tioga	Liberty	8/3/2018
193	East	335086	Tioga	Liberty	8/3/2018
194	East	335087	Tioga	Liberty	8/3/2018
195	East	335088	Tioga	Liberty	8/3/2018
196	East	335090	Tioga	Liberty	8/3/2018
197	East	335806	Tioga	Delmar	11/2/2021
198	East	335908	Lycoming	Jackson	10/26/2018
199	East	335909	Lycoming	Jackson	10/26/2018
200	East	336349	Lycoming	Hepburn	8/4/2022
201	East	337112	Clearfield	Brady	5/28/2021
202	East	340148	Bradford	Orwell	1/15/2021
203	East	341500	Tioga	Liberty	11/18/2019
204	East	342658	Bradford	Monroe	4/22/2020
205	East	342978	Bradford	Monroe	4/22/2020
206	East	343702	Susquehanna	Auburn Twp	12/4/2019
207	East	345209-346697	Wyoming	Meshoppen Twp	7/2/2020
208	East	346886	Wyoming	Meshoppen Twp	7/2/2020

209	East	347944	Bradford	Orwell	1/15/2021
210	East	347960	Bradford	Orwell	1/15/2021
211	East	348683	Bradford	Monroe	4/22/2020
212	East	348684	Bradford	Monroe	4/22/2020
213	East	349670-1	Wyoming	Meshoppen Twp	1/6/2021
214	East	349670-2	Wyoming	Meshoppen Twp	1/6/2021
215	East	349670-3	Wyoming	Meshoppen Twp	1/6/2021
216	East	349670-4	Wyoming	Meshoppen Twp	1/6/2021
217	East	349730	Wyoming	Meshoppen Twp	1/6/2021
218	East	349732	Wyoming	Meshoppen Twp	1/6/2021
219	East	349733	Wyoming	Meshoppen Twp	1/6/2021
220	East	349737	Wyoming	Meshoppen Twp	1/6/2021
221	East	349749	Wyoming	Meshoppen Twp	1/6/2021
222	East	349767	Wyoming	Meshoppen Twp	1/6/2021
223	East	349768	Wyoming	Meshoppen Twp	1/6/2021
224	East	349769	Wyoming	Meshoppen Twp	1/6/2021
225	East	349788	Wyoming	Meshoppen Twp	1/6/2021
226	East	349881	Wyoming	Meshoppen Twp	1/6/2021
227	East	354276	Bradford	Monroe	2/17/2022
228	East	355977	Susquehanna	Franklin Twp	3/26/2024
229	East	356411	Susquehanna	Dimock	5/24/2024
230	East	356598	Tioga	Delmar	11/2/2021
231	East	358383	Bradford	Terry	9/9/2021
232	East	359719	Bradford	Troy	4/5/2022
233	East	359877	Susquehanna	Auburn Twp	4/10/2024
234	East	360462	Wyoming	Windham Twp	12/18/2024
235	East	360463	Wyoming	Windham Twp	12/18/2024
236	East	360490-364626	Susquehanna	Lenox Twp	9/19/2024
237	East	360620-1	Susquehanna	Lenox Twp	9/19/2024
238	East	360620-2	Susquehanna	Lenox Twp	4/25/2025
239	East	360839	Susquehanna	Lenox Twp	9/19/2024
240	East	360890	Susquehanna	Lenox Twp	9/19/2024
241	East	360951	Susquehanna	Lenox Twp	9/19/2024
242	East	361063	Susquehanna	New Milford Twp	1/19/2022
243	East	361209	Tioga	Sullivan Twp	3/17/2023
244	East	361497	Susquehanna	Lenox Twp	9/19/2024
245	East	361589	Susquehanna	Lenox Twp	9/19/2024
246	East	362465	Susquehanna	Lenox Twp	9/19/2024
247	East	362566	Tioga	Middlebury Twp	5/26/2022
248	East	362693	Tioga	Middlebury Twp	5/26/2022
249	East	363248	Susquehanna	Lenox Twp	9/19/2024
250	East	364525	Susquehanna	Lenox Twp	9/19/2024
251	East	365101	Bradford	Springfield Twp	7/8/2022
252	East	365282	Bradford	Springfield Twp	7/21/2022
253	East	365308	Cameron	Shippen Twp	1/9/2023
254	East	365344	Tioga	Middlebury Twp	8/4/2022
255	East	365345	Tioga	Middlebury Twp	7/13/2022

256	East	365456	Bradford	Springfield Twp	12/6/2023
257	East	365609	Cameron	Shippen Twp	1/9/2023
258	East	366180	Cameron	Shippen Twp	1/9/2023
259	East	366805	Susquehanna	Lenox Twp	9/14/2022
260	East	367110	Susquehanna	Lenox Twp	11/9/2022
261	East	368134	Bradford	Columbia	11/10/2022
262	East	370045	Wyoming	Meshoppen Twp	4/10/2024
263	East	372907	Bradford	Terry Twp	8/1/2023
264	East	373555	Susquehanna	Lenox Twp	9/19/2024
265	East	381422	Bradford	Middlebury Twp	7/31/2024
266	East	381987	Bradford	Albany Twp	7/31/2024
267	East	382174	Tioga	Delmar	8/14/2024
268	East	384475	Bradford	Springfield Twp	12/11/2024
269	Northwest	250746	Venango	Oakland	12/24/2007
270	Northwest	251599	Crawford	Woodcock	1/30/2008
271	Northwest	252267	Erie	Millcreek	4/11/2008
272	Northwest	252267	Erie	Millcreek	4/11/2008
273	Northwest	252818	McKean	Foster	4/4/2008
274	Northwest	253478	Forest	Hickory	4/29/2008
275	Northwest	254802	Crawford	Hayfield	5/22/2008
276	Northwest	254900	Forest	Howe	7/24/2008
277	Northwest	256043	McKean	Bradford	7/29/2008
278	Northwest	256642	Erie	Waterford	10/8/2013
279	Northwest	257185	McKean	Hamilton	9/12/2008
280	Northwest	257185	McKean	Hamilton	9/12/2008
281	Northwest	257867	Jefferson	Winslow	10/10/2008
282	Northwest	258217	Jefferson	Clover	10/28/2008
283	Northwest	258396	McKean	Hamilton	10/30/2008
284	Northwest	258396	McKean	Hamilton	10/30/2008
285	Northwest	258483	McKean	Foster	10/30/2008
286	Northwest	258484	Warren	Sheffield	11/10/2008
287	Northwest	258625	Clarion	Limestone	1/27/2009
288	Northwest	258625	Clarion	Limestone	1/27/2009
289	Northwest	259040	Elk	Jones	11/13/2008
290	Northwest	259064	Clarion	Limestone	3/26/2009
291	Northwest	259354 261083	Jefferson	Knox	3/27/2009
292	Northwest	260043	Warren	Sheffield	12/23/2008
293	Northwest	260496	McKean	Corydon	2/17/2009
294	Northwest	260565	Venango	Cranberry	8/13/2009
295	Northwest	260916	McKean	Foster	3/10/2009
296	Northwest	261105	Jefferson	Oliver	4/2/2009
297	Northwest	262473	Warren	Mead	8/3/2009
298	Northwest	262648	Jefferson	Knox	5/27/2009
299	Northwest	262648	Jefferson	Knox	5/27/2009
300	Northwest	262683	McKean	Foster	6/1/2009
301	Northwest	262771	Jefferson	Knox	7/13/2009
302	Northwest	263617	Warren	Glade	2/18/2010

303	Northwest	263963	McKean	Bradford	7/21/2009
304	Northwest	264898	McKean	Bradford	3/5/2010
305	Northwest	265297	Jefferson	Knox	9/11/2009
306	Northwest	265323	Clarion	Elk	9/10/2009
307	Northwest	266017	Jefferson	Warsaw	10/19/2009
308	Northwest	266591	Crawford	Oil Creek	6/24/2011
309	Northwest	267033	Clarion	Elk	1/15/2010
310	Northwest	267519 268448	McKean	Bradford	12/11/2009
311	Northwest	267519 268448	McKean	Bradford	12/11/2009
312	Northwest	267880	Clarion	Elk	1/20/2010
313	Northwest	267880	Clarion	Elk	1/20/2010
314	Northwest	269055	Forest	Kingsley	3/22/2010
315	Northwest	269244	Warren	Glade	9/27/2010
316	Northwest	271422	McKean	Bradford	10/19/2010
317	Northwest	271490	Warren	Sheffield	6/17/2010
318	Northwest	272189	Forest	Hickory	8/2/2010
319	Northwest	272948	McKean	Bradford	12/17/2010
320	Northwest	273024	Clarion	Madison	7/18/2014
321	Northwest	273321	Crawford	Spring	1/28/2011
322	Northwest	273460	McKean	Corydon	Oct. 2010
323	Northwest	274735	Elk	Jones	12/23/2010
324	Northwest	276220	McKean	Foster	2/9/2011
325	Northwest	276776	Forest	Hickory	3/28/2012
326	Northwest	276776	Forest	Hickory	10/20/2011
327	Northwest	276776	Forest	Hickory	3/28/2012
328	Northwest	276776	Forest	Hickory	3/28/2012
329	Northwest	276776	Forest	Hickory	3/28/2012
330	Northwest	276776	Forest	Hickory	3/28/2012
331	Northwest	276776	Forest	Hickory	3/28/2012
332	Northwest	276776	Forest	Hickory	3/28/2012
333	Northwest	276776	Forest	Hickory	3/28/2012
334	Northwest	276776	Forest	Hickory	3/28/2012
335	Northwest	276776	Forest	Hickory	3/28/2012
336	Northwest	276776	Forest	Hickory	3/28/2012
337	Northwest	276776	Forest	Hickory	5/3/2011
338	Northwest	276823	Forest	Hickory	5/4/2011
339	Northwest	277438	McKean	Bradford	7/13/2011
340	Northwest	278982	Warren	Pleasant	5/4/2012
341	Northwest	281151	Elk	Jones	8/8/2011
342	Northwest	281911	Indiana	West Wheatfield	8/30/2013
343	Northwest	287891	Butler	Winfield	6/4/2013
344	Northwest	288690	Butler	Jefferson	11/5/2012
345	Northwest	289916	Clarion	Toby	11/29/2012
346	Northwest	290406	Lawrence	Pulaski	11/13/2013
347	Northwest	290406	Lawrence	Pulaski	11/19/2013
348	Northwest	290406	Lawrence	Pulaski	11/20/2013
349	Northwest	290406	Lawrence	Pulaski	10/7/2013

350	Northwest	291029	Butler	Winfield	9/7/2012
351	Northwest	292020	Warren	Sugar Grove	Sept. 2012
352	Northwest	293565	Warren	Pleasant	1/4/2013
353	Northwest	294446	Forest	Kingsley	7/19/2013
354	Northwest	294734	Warren	Pleasant	7/11/2013
355	Northwest	294947	McKean	Foster	8/28/2013
356	Northwest	296020	Butler	Forward	8/28/2013
357	Northwest	297302	Elk	Bennezette	12/10/2015
358	Northwest	297871	Clarion	Porter	3/24/2014
359	Northwest	298337	Warren	Glade	10/1/2013
360	Northwest	299917	Forest	Kingsley	6/9/2016
361	Northwest	300296	McKean	Lafayette	Nov. 2013
362	Northwest	305257	Butler	Connoquenessing	12/12/2014
363	Northwest	305506	Warren	Mead	7/28/2014
364	Northwest	306890	Warren	Farmington	10/28/2014
365	Northwest	307002	Venango	Cranberry	12/9/2014
366	Northwest	307679	Jefferson	Eldred	10/30/2014
367	Northwest	308544	Forest	Kingsley	8/24/2016
368	Northwest	309793	Butler	Oakland	12/10/2015
369	Northwest	309804	McKean	Otto	3/9/2016
370	Northwest	310459	Jefferson	Warsaw	1/22/2020
371	Northwest	310559	Clarion	Porter	6/13/2017
372	Northwest	310703	Clarion	Millcreek	8/29/2019
373	Northwest	311304	Lawrence	Pulaski	2/2/2016
374	Northwest	313247-1	Clarion	Limestone	5/7/2019
375	Northwest	313247-2	Clarion	Limestone	5/7/2019
376	Northwest	313247-3	Clarion	Limestone	5/7/2019
377	Northwest	313247-4	Clarion	Limestone	5/7/2019
378	Northwest	314644	Lawrence	Pulaski	6/9/2016
379	Northwest	314763	Butler	Muddycreek	12/10/2015
380	Northwest	316381	Clarion	Redbank	8/3/2017
381	Northwest	318101	Erie	Washington	3/6/2018
382	Northwest	321627	Butler	Comcord	3/31/2017
383	Northwest	331396	Venango	Sugarcreek	11/7/2018
384	Northwest	333763	Warren	Glade	3/21/2019
385	Northwest	336405	McKean	Bradford	3/21/2019
386	Northwest	336475	McKean	Bradford	3/21/2019
387	Northwest	337112	Clearfield	Brady Township	5/28/2021
388	Northwest	344019	Clarion	Licking Township	6/10/2021
389	Northwest	345911	Jefferson	Heath	10/28/2020
390	Northwest	346646	Armstrong	Boggs	10/20/2022
391	Northwest	347453	Indiana	Center	5/11/2021
392	Northwest	351275	Butler	Connoquenessing	5/13/2022
393	Northwest	351410	Clarion	Porter	10/24/2024
394	Northwest	352432	Armstrong	Kiskeminetas	8/6/2024
395	Northwest	352647	Butler	Connoquenessing	3/9/2023
396	Northwest	357415	Butler	Connoquenessing	11/15/2022

397	Northwest	357453	Jefferson	Warsaw	11/15/2022
398	Northwest	359788	Clarion	Millcreek	4/10/2024
399	Northwest	362602	Armstrong	South Bend	10/24/2024
400	Northwest	362692	Butler	Connoquenessing	8/22/2022
401	Northwest	365138	Clarion	East Brady	4/16/2025
402	Northwest	365452	Warren	Eldred	8/7/2023
403	Northwest	367967	Clarion	Beaver	8/15/2023
404	Northwest	370582	Erie	Harborcreek	9/9/2024
405	Northwest	373431	Venango	Cranberry	8/21/2024
406	Northwest	373559	Warren	Mead	12/16/2025
407	Northwest	382179	Elk	Jones	4/16/2025
408	Northwest	ORDER	McKean	Bradford	2/23/2010
409	Northwest	ORDER	McKean	Bradford	2/23/2010
410	Northwest	ORDER	McKean	Bradford	2/23/2010
411	Northwest	ORDER	McKean	Bradford	2/23/2010
412	Northwest	ORDER	McKean	Bradford	2/23/2010
413	Northwest	ORDER	McKean	Bradford	2/23/2010
414	Northwest	ORDER	McKean	Bradford	2/23/2010
415	Northwest	ORDER	McKean	Bradford	2/23/2010
416	Northwest	ORDER	McKean	Bradford	2/23/2010
417	Northwest	ORDER	Indiana	East Wheatfield	9/2/2008
418	Northwest	ORDER	Indiana	East Wheatfield	9/2/2008
419	Northwest	ORDER	Indiana	East Wheatfield	9/2/2008
420	Northwest	ORDER	Indiana	East Wheatfield	9/2/2008
421	Northwest	ORDER	Indiana	East Wheatfield	9/2/2008
422	Northwest	ORDER	Indiana	West Mahoning	2/12/2008
423	Northwest	ORDER	Indiana	Cherryhill	1/15/2008
424	Southwest	288825	Greene	Morgan	3/2/2015
425	Southwest	291965	Westmoreland	Donegal	6/4/2013
426	Southwest	294666	Washington	Cross Creek	6/17/2013
427	Southwest	301088	Westmoreland	Donegal	12/16/2013
428	Southwest	302442	Westmoreland	Donegal	8/25/2014
429	Southwest	306873	Westmoreland	Donegal	12/5/2014
430	Southwest	309063	Westmoreland	Hempfield	1/6/2016
431	Southwest	310158	Westmoreland	Donegal	3/20/2015
432	Southwest	314330	Greene	Morgan	12/14/2015
433	Southwest	314341	Greene	Cumberland Twp	10/27/2015
434	Southwest	314841	Washington	North Bethlehem	11/25/2015
435	Southwest	317342	Westmoreland	Derry	7/7/2017
436	Southwest	336198	Allegheny	Plum Borough	10/12/2018
437	Southwest	336945	Greene	Cumberland Twp	12/17/2018
438	Southwest	362414	Washington	North Bethlehem	6/21/2022
439	Southwest	362492	Washington	North Bethlehem	6/9/2022
440	Southwest	364055	Washington	North Bethlehem	6/21/2022
441	Southwest	366381	Greene	Cumberland Twp	12/28/2023
442	Southwest	ORDER	Washington	West Pike Run	3/27/2008
443	Southwest	ORDER	Fayette	Jefferson	1/4/2008

444	Southwest	ORDER	Greene	Washington	9/11/2014
	7/8/2025				

TUESDAY, MARCH 25, 2025

DEP Reports 575 Water Supply/Stray Gas Complaints About Oil & Gas Operations In Last 2 Years; Investigation Can Take A Year, Sometimes 2-3 To Find Those Responsible

On March 20, the Department of Environmental Protection provided an update to the agency's Oil and Gas Technical Advisory Board on water supply/stray gas complaints.

Jennifer Means, Oil & Gas Program Manager for the Northcentral/Eastern District, provided the update for all the Oil and Gas Districts.

Means reported during 2023 and 2024, DEP received a total of 575 new water supply/stray gas complaints from the public-- 298 in her Northcentral/Eastern Region, 76 in the Northwest and 201 in the Southwest.

During that same time period, DEP's Oil and Gas offices resolved 395 complaints-- 241 in Northcentral/Eastern, 55 in the Northwest and 99 in the Southwest-- however, they were not necessarily the same complaints that came in the door during 2023-24.

In terms of positive findings of water supply/stray gas impacts within the "resolved cases," DEP found 33-- 26 in Northcentral/Eastern, 6 in Northwest and one in Southwest-- again, these are not the same cases that came in the door during 2023-24.

Means said in the Northcentral/Eastern District water supply/stray gas complaints "is really the biggest issue we deal with every day."

"We have other critical things that come up, obviously, but throughout the course of our 15-plus year existence, this has been our big issue."

"It's also difficult to determine up front if a case is stray gas-related just in looking at our complaint data. Because almost all of those complaints don't come in saying there's gas in the water.

"We do get a few of those, and some that say they're lighting their water on fire.

"But most of them come in as something else, like discoloration, turbidity, even odor, various things.

"So, when you're looking at complaints that are still open and trying to determine-- is this stray gas related-- you can't really do that by the way the call or the information initially came into the Department.

"It's really not until the end of that investigation that we can kind of say whether or not it's actually a stray gas case."

Different Regions, Different Problems

"It's a little bit different in the other districts with the historical well development they've had going on, so in the Eastern District most of the gas migration we're dealing with is obviously related to the unconventional [shale] well development."

"In the last two years, in the Eastern District specifically, again just looking at some numbers in a different way, we look at the number of new gas migration cases that we're investigating. And we have about 12 of those.

"Those 12 cases involve about 25 water supplies.

“So, of those just in the 23-24 timeframe, 3 of those cases were actually closed out of non-impacts. Those 3 separate cases involved a total of 8 water supplies.

“Three of the cases were presumed [within 2,500 feet of an oil and gas well] to be positive impacts and those investigations are still ongoing as well.

“The remaining 6 cases, involving 14 water supplies, those investigations are still ongoing to determine if there's impacts as a result of oil and gas activity.”

“I think it's important to note that even once we make a determination, obviously if that determination is positive that there was an impact, that investigation goes on, often for a long time, in trying to determine the exact source or cause of the impacts and having remedial measures take place to actually resolve the problem.”

2-3 Year Investigations Not Unusual

In response to a later question, Means said, I don't know that I have an average, [of how long investigations take] but I can just give you some idea from some recent cases we've dealt with.

“We had a fairly significant case where we made a number of positive determinations in the last year.

“That investigation initiated in 2021. It was a situation where there were not many gas wells very close to the area of impact.

“So, it was a situation where the wells that we believe to be the source of the impact are a mile or so away, which makes it, again more challenging, again multiple operators involved.

“So, that was one situation. We certainly do have in gas migration cases, you can be talking a few-year period.

“We also had a couple of cases. I'm going to say the beginning of 2023, where we've been investigating two cases involving multiple water supplies.

“One of those we did resolve the end of last year as non-impact, [was] closer to the two-year timeframe.”

“So, I think two to three years for a significant gas migration case is probably not unusual.”

“We do have some that have been going on for many years. In talking to my counterparts in the Northwest, they even said the same thing even when dealing with conventional operations, especially if you get into situations where the closest wells aren't the obvious problem.”

Geology Makes Problem Worse

Means said in trying to understand why the water supply/stray gas problem is so much worse in the Northcentral/Eastern District than other areas comes down to geology.

“As I said, we all feel this is pretty much the biggest problem we deal with every day, so we talk about it a lot. The thing I've heard the most that's different for us in the eastern district is we've got this highly fractured geology in the shallow subsurface.

“Certain counties in our district are more prone to these problems. We have a lot of issues in Tioga, Bradford, Susquehanna counties.

“We have a lot of impacts that are a considerable distance away from the gas wells that are the potential source or kind of determined to be the source, up to a mile or so away in some cases.

“So, it seems that the possible pathway here is that if there's any defective cement issue, even at some point in the wellbore that the gas perhaps migrates up the well board to some degree until it hits one of these fractures or faults and then kind of stair-steps away from the well, possibly showing up in a water supply or surface water a mile, half-mile or so away from the actual well.

“Which makes it kind of difficult to determine that force, and especially if there's multiple well paths or operators in the area.”

During last year’s report, Kurt Klapkowski, DEP Deputy Secretary for Oil and Gas Management, also highlighted the complexity of these investigations especially in areas with underground coal mining, natural gas pipelines, gas storage areas and thousands of abandoned oil and gas wells.

“When you start to talk about all those facilities at one time, it's like you're trying to find a needle in a stack of needles,” said Klapkowski. “And deciding where that's coming from, it gets really complex, really fast. [Read more here]

Complaint Trends

Means also reported, for comparison, from 2009 to 2014 there were 1,160 water supply/stray gas complaints in the Northcentral/Eastern District with 132 found to be impacted.

In that same timeframe there were 4,875 unconventional shale gas wells drilled.

From 2019 to 2024 there were 1,077 complaints in her District with 121 positive determinations.

A total of 1,593 new shale gas wells were drilled.

“So, it is kind of interesting to see that even though approximately a third of the number of the wells were drilled, our statistics [show] it’s around the same …number of water supply impacts,” said Means.

About this time last year, DEP also reported on water supply/stray gas complaints saying they were seeing an upward trend in the number of investigations and positive determinations. [Read more here]

When asked last year why there are more water supply complaints, DEP said more people are paying more attention to these issues. [Read more here]

Online Reporting

DEP has two webpages that report on water supply/stray gas complaints.

DEP has a searchable online database of cases that will show whether there has been a positive, negative or underdetermined outcome so far in water supply/stray gas complaints.

Cases can be searched by date, county, municipality and DEP and by the nature of the problem and the general cause.

No other identifying information is made available.

DEP also maintains a running list of Water Supply Determination Letters where they have officially determines a private water supply has been impacted by oil and gas activities.

The municipality and county is listed and the names of individuals are redacted.

There are currently 438 cases on that list.

More Background - Presumption

Pennsylvania law provides, generally, an oil and gas well owner is presumed to be responsible for water supply contamination if the oil and gas well is within 1,000 feet of a water supply for a conventional well and 2,500 feet for an unconventional shale gas well.

An additional stipulation is the pollution occurred within six months after the completion of drilling or fracking in the case of a conventional well and 12 months in the case of a shale gas well.

The well owner has the opportunity to rebut this presumption with their own evidence.

If notified by a landowner or a water supply operator of suspected impacts of oil and gas well drilling, the law requires DEP to "Within ten days of notification, the department shall investigate the claim and make a determination within 45 days following notification."

As Means said, while it is much easier to make a determination in cases involving this presumption, it practically never happens within the 45 days required by law because of the complexities of these cases.

There are also two steps to DEP's water supply/stray gas determinations.

Step 1 is making a determination about whether a water supply has been impacted by **any oil and gas operation**.

This step, itself, can take months, during which time the landowner is on their own to provide themselves clean water. [Read more here.]

Step 2 is making a determination about whether a specific oil and gas operation impacted a specific water supply.

As Means reported, Step 2 can take years to get to the point where an oil and gas well owner could be ordered by DEP to provide clean, replacement water.

DEP has a Frequently Asked Questions available on presumptive liability for pollution of water supplies by oil and gas drilling.

For more information on Board activities, visit DEP's Oil and Gas Technical Advisory Board webpage. Questions should be directed to Todd Wallace, at twallace@pa.gov or (717) 783-6395.

Visit DEP's Office of Oil and Gas Management webpage to learn more about this program.

*(**Photo:** Wall Street Journal story from 2011 stray gas contamination of a water supply in Bradford County from shale gas drilling.)*

Resource Links:

-- DEP Reports The Number Of Methane Contaminated Water Supplies From Oil & Gas Drilling Is Up 'Across The Board,' 'Not A Good Trend' [PaEN]

-- Environmental Health Project To Hold April 1 Webinar On What The Shapiro Administration Can Do To Better Protect Public Health From The Impacts Of Shale Gas Development [PaEN]

-- Environmental Health Project Seeking Communities To Participate In HealthWatch Program To Better Understand Local Health Impacts Of Shale Gas Development [PaEN]
-- Presentations Posted From 2025 Shale Gas & Public Health Conference Featuring Health Experts, Scientists, Advocacy Groups, Workers On Health, Environmental Impacts Of Shale Gas Development [PaEN]

PA Oil & Gas Industry Public Notice Dashboards:

-- PA Oil & Gas Weekly Compliance Dashboard - March 22 to 28 - Failed To Comply With Well Plugging Order For 63 Months; Abandoned Conventional Well Violations Hit 113; Another Conventional Well Explosion, Same Owner [PaEN]
-- PA Oil & Gas Industrial Facilities: Permit Notices/Opportunities To Comment - March 29 [PaEN]
-- DEP To Hold May 7 Hearing On Proposed Title V Air Quality Permit For Tennessee Gas Pipeline Compressor Station 219 In Jefferson Twp., Mercer County [PaEN]
-- DEP Invites Comments On 401 Water Quality Certification For Rover Pipeline Rover-Bulger Compressor Station, Harmon Creek Meter Station Expansion In Smith Twp., Washington County [PaEN]
-- DEP Invites Comments On Chapter 105 Permit For A MarkWest Liberty 4.5 Mile, 20-Inch Natural Gas Pipeline In Allegheny, Washington Counties Impacting Montour Trail Property [PaEN]
-- DEP Invites Comments On Air Permit For Kratos Cryptocurrency Mining Facility Powered By Natural Gas In Clinton County [PaEN]
-- Susquehanna River Basin Commission Approved 50 Shale Gas Well Pad Water Use General Permits In February [PaEN]
-- DEP Posted 103 Pages Of Permit-Related Notices In March 29 PA Bulletin [PaEN]

Related Articles This Week:

-- Criminal Convictions; Record Penalties, Restitution Of Over $158.3 Million Highlight Big Shale Gas, Related Petrochemical Industry Compliance History In Pennsylvania [PaEN]
-- DEP Reports 575 Water Supply/Stray Gas Complaints About Oil & Gas Operations In Last 2 Years; Investigation Can Take A Year, Sometimes 2-3 To Find Those Responsible [PaEN]
-- Daily Grind Living Next To Oil & Gas Industry: Spills, Polluted Water Supplies, Smells Like Gas, Noise, Air Pollution, Explosions, Truck Traffic, Erosion, Radioactive Waste, Gas Flares, Dust, Lights, Road Dumping Waste, Abandoned Wells [PaEN]
-- DEP To Recommend Environmental Quality Board Accept A Petition For Study To Increase Setbacks From Shale Gas Wells At April 8 Meeting [PaEN]
-- DEP Soliciting Bids On 3rd Conventional Abandoned Oil & Gas Well Plugging Contract For 19 Wells In Clarion, Jefferson Counties At Taxpayer Expense [PaEN]
-- DEP: US Interior Dept. Withdraws Orphan Oil & Gas Well Regulatory Improvement Grant Program To Help Prevent Future Well Abandonments, A Severe Problem In PA [PaEN]

-- Susquehanna River Basin Commission: Low Stream Flows Triggering Restrictions On 19 Shale Gas Water Withdrawals, 17 More Approaching Restrictions [PaEN]
-- Susquehanna River Basin Commission Releases Natural Gas Industry Water Use Report 2019-2023
-- PUC Launches Review Of Electric Grid Impacts From Data Center Growth, Sets April 24 Hearing [PaEN]
-- PJM Interconnection Reliability Initiative Attracts 94 Applications For 26.6 GW Of New Electric Generation Capacity; Reviews To Be Completed By 2026; List Of Projects Not Available Now [PaEN]

NewsClips:

-- WHYY: Bucks County Residents Sue Energy Transfer/Sunoco Pipeline Over Pipeline Leak That Contaminated Their Wells
-- Courier Times: Bucks County Residents Suing Energy Transfer/Sunoco Pipeline For Pipeline Leak That Poisoned Drinking Water
-- Chesapeake Bay Journal - Karl Blankenship: Pennsylvania Caps 300 Abandoned Conventional Oil & Gas Wells In 2 Years
-- The Energy Age Blog: Fracking Under Ohio's Largest State Park Gets Underway; How The Industry Has Changed Guernsey County
-- High Country News: President Halts Historic Orphaned Oil & Gas Well Plugging Program
-- PA Capital-Star: PA Public Utility Commission Sets Hearing On A.I. Data Centers' Impacts On Electricity Grid
-- Utility Dive: PJM Fast-Track Interconnection Process Draws 26.6 GW In New Electric Generation Capacity
-- PennLive Guest Essay: Expect Higher Electric Bills This Summer By As Much As 20% [Thousands Of Energy Projects Stuck In PJM Review] - By Rob Altenburg, PennFuture
-- Kleinman Center For Energy Policy Blog: More Bad Ideas To Promote Natural Gas, More Clean Energy Solutions For Load Growth - By John Quigley, Senior Fellow, Fmr DEP Secretary

[Posted: March 25, 2025] PA Environment Digest

SATURDAY, MARCH 29, 2025

PA Oil & Gas Weekly Compliance Dashboard - March 22 to 28 - Failed To Comply With Well Plugging Order For 63 Months; Abandoned Conventional Well Violations Hit 113; Another Conventional Well Explosion, Same Owner

From March 22 to 28, DEP's Oil and Gas Compliance Database shows oil and gas inspectors filed 815 inspection entries.

Follow these links to spreadsheets showing the violations and inspections occurring between March 22 to 28--

Click Here for violations issued.

Click Here for inspection entries.

Enforcement Actions Taken Last Week

So far this year, DEP took these actions as of March 21--

-- NOVs Issued In Last Week: 200 conventional, 6 unconventional
-- Year To Date - NOVs Issued: 1,029 conventional and 293 unconventional
-- Enforcements 2025: 95 conventional and 39 unconventional (orders, agreements)
-- Inspections Last Week: 487 conventional and 357 unconventional
-- Year To Date - Inspections: 4,434 conventional and 6,478 unconventional

Another Conventional Well Explosion

Kriebel Natural Gas Co LLC - Violations: Failed To Manage Production Fluids, Wastewater

March 25, 2025 inspection of the Wissinger 001 conventional well in **East Huntingdon Township, Westmoreland County** in response to a report of an explosion at the well site. An explosion of the production storage tank occurred at 10:25 a.m while the well tender was blowing out the well. DEP arrived on site at 11:30 a.m.

"It appears that a faulty tank ground on the poly brine tank allowed static electricity to build up and during the process of "blowing the well" to the tank, which is a common practice to remove brine/fluids from the well-bore to allow gas to be produced in higher quantities, it is believed that static charge then ignited the gas vapors in the tank causing a flash fire and extreme pressure that resulted in the tank explosion and also the fire to be immediately extinguished.

"At that time the well tender, who was blowing the well and at the wellhead, immediately shut the well in. No injuries were reported. DEP inspection report Part 3.

A large piece of the production tank landed about 30 feet from its original site and the remainder of the tank was found 140 feet away. DEP inspection report Part 2.

About 420 gallons of oil and wastewater was released and heavily contaminated an area of about 40 feet around the production equipment. The contamination also went into a ditch and traveled roughly 120 feet down slope from the site.

Steps were being taken to remediate the site during the inspection.

Violations issued. Response requested by April 9. DEP inspection report Part I.

On March 19, firefighters and DEP responded to another explosion and fire at a conventional well owned by Kriebel Natural Gas Co LLC in Manor Borough, Westmoreland County. Read more here.

17 Abandoned Conventional Wells

Amer Natural Resources LLC - Violations: 7 Wells, Failed to Comply With Plugging Order (63 Months)
March 20, 2025 inspections of 7 conventional wells in **Allegheny County** found them abandoned and not plugged and as a result the owner failed to comply with a DEP order issued on December 12, 2019 to plug the wells. Owner also failed to submit annual production, waste generation and well integrity reports. No request made of well owner. Amer Natural Resources holds 49 permits. The wells included--
-- Aleppo Twp.: Merle Minick Unit 1; Merle Minick Unit 2;
-- Glenfield Boro: John Straka Unit 1; John Straka Unit 2
-- **Ohio Twp.:** Grove/Grambo Unit 1; Grove/Grambo Unit 2; John Lenzner Unit 1

Chris E. Burke - Violations: Conventional Abandoned Well
March 26, 2025 inspection of the BE Burke 122-3 conventional well in **Jackson Township, Greene County** found the well abandoned and not plugged. Well owner also failed to submit annual production, waste generation and well integrity reports. Well completed in 2011. Violations issued. Response requested by April 16. Burke holds 1 permit. DEP inspection report.

Keystone Crude LLC - Violations: Conventional Abandoned Well
March 25, 2025 inspection of the BN McCormick 1 conventional well in **Robinson Township, Allegheny County** found the well abandoned and not plugged and leaking gas. Well owner also failed to submit annual production, waste generation and well integrity reports. Response requested by April 10. Keystone holds 34 permits. DEP inspection report.

Diversified Prod LLC - Violations: 4 Abandoned Conventional Wells
March 17 - 21, 2025 inspections of three conventional wells in Indiana, Mercer and Westmoreland County found them abandoned and not plugged. Response requested by April 10 or 11.
-- Indiana County, Armstrong Twp.: ESSIE E Dible 4 4
-- Indiana County, Grant Twp.: JH Weaver & Company 8
-- Mercer County, Findley Twp.: Nelson 4
-- Westmoreland County, Washington Twp.: Rachel Fulton 681 (from complaint)

Edward E. & Frederick J. Craig: - Violations: Abandoned Conventional Well, No Reports
March 17, 2025 inspection of the John Jameson 3 conventional well in **Fairview Township, Butler County** found it abandoned and not plugged. Also failed to submit annual production, waste generation and well integrity reports. Response requested by April 4. The Craigs hold 8 permits. DEP inspection report.

EQT Production Co. - Violations: Abandoned Conventional Well
March 21, 2025 inspection found the David Spangler 454 conventional well in **Monroeville Borough, Allegheny County** abandoned and not plugged. First plug failed to stop the flow of gas. Response requested by April 10. DEP inspection report.

Red Lion Gas Coop Assn. - Violations: Abandoned Conventional Well
March 14, 2025 inspection of the Mark Williams 1 conventional well in **Jefferson Township, Fayette County** found the well abandoned and not plugged. Owner failed to submit annual production, waste generation and well integrity reports. Original violations

issued February 7, 2025. Violations continued. Response requested by April 14. Red Lion holds two permits. DEP inspection report.

Reel Resources, Inc. - Violations: Abandoned Conventional Well, Leaking Gas (30 Months)
March 14, 2025 inspection of the W. Clyde Swank 1 conventional well in **Allegheny Township, Westmoreland County** found it abandoned, not plugged and still leaking gas. Original violations September 7, 2022. Violations continued. Response requested by April 14. Reel hotels 40 permits. DEP inspection report.

1 Abandoned Shale Gas Well

Apex Energy (PA) LLC - Violations: Abandoned Shale Gas Well
March 19, 2025 inspection of the Marian Laskowski 7 shale gas well in **Hempfield Township, Westmoreland County** found it abandoned and not plugged. Failed to have emergency response plan. Well drilled in 2008. Response requested by April 9. DEP inspection report.

[Note: DEP inspected the Marian Laskowski 6 shale gas well March 6 in Hempfield Township and also found it abandoned and not plugged. DEP inspection report.]

Methane Reduction Plugging Grants

Curtis Oil Inc.
March 26, 2025 inspections of 11 conventional wells in **Lafayette, and Otto Townships, McKean County** related to Methane Reduction Plugging Grants.

113 Abandoned Conventional, 39 Abandoned Shale Gas Well Violations 2025

Abandoned Conventional: So far in 2025, DEP issued or continued 113 violations to 39 conventional oil and gas well owners for abandoning and not plugging their wells- [3D Resources LLC ; Amer Natural Resources LLC; WB Anderson; Apollo Resources LLC; Baird Oil Co.; Bialy Gas Production LLC; Chris E. Burke; Edward E. & Frederick J. Craig; Crude A Co - Randy L. Larkin; Randy A. Dietterich; Diversified Production LLC; Equitrans LP; EQT Production Co.; Keystone Crude LLC; Kiski Valley Gas Co.; Leechburg Gas Co.; Manufacturers Light & Heat Co; Mid East Oil Co.; MTN Energy; Charles E. Myers; Myers Gas; Oil & Gas MGMT Co. LLC, PA Mineral SVCS LLC; PBS Coals Inc; Pillar Energy PA, LLC; Pin Oak Energy Partners, LLC; Red Lion Gas Coop Assn; Reel Resources, Inc; Raymond Sawyer; Fred C. Scheel; SK Opr Inc.; Stockman LLC; Stonehaven Energy MGT Co. LLC; Andrew F. Suchko; Thomas Thurma Jean; Timberline Energy, Inc.; Vessels Coal Gas Inc.; Washington Energy Co LLC; Ronald Wise; Mary A. Woodring].

In 2024, DEP issued 860 new or continued violations to conventional oil and gas well owners for abandoning and not plugging their wells.

In 2023, DEP issued 512 violations to conventional well owners for abandonment.

Abandoned Shale Gas: So far in 2025, DEP issued or continued 40 violations to 10 shale gas drilling companies for abandoning and not plugging their wells-- [Anegada Energy LLC; Apex Energy (PA) LLC; Blackhill Energy LLC; Diversified Production LLC;

Diversified Production LLC; EQT ARO LLC; EQT Chap LLC; EQT Production Co.; Rice Drilling B LLC; Roulette Oil & Gas LLC; Taft Operating LLC].

In 2024, 47 violations were issued or continued to 12 shale gas well owners for abandoning and not plugging their wells.

In 2023, DEP issued or continued 20 violations to 10 shale gas well owners for abandoning and not plugging their wells. Read more here.

Water Supply/Stray Gas Investigation

Indiana County, Armstrong Township
On March 26, 2025 DEP did a water supply complaint stray gas investigation inspection s of Diversified Prod LLC conventional wells-- Ralph E. Greene 4133, Ralph E. Greene 3, RE Greene 5 and Vera Trimarchi 4, Vera Trimarchi 4863; Greylock Conventional LLC's Lions Health Camp 3 well; Greylock OPC LLC Fisher & Peelor 1 and Dorothy A. Musser 1 wells; MTN V Oil & Gas Inc. Clyde McQuown 2 well and was unable to detect any gas leaks from these wells

Spills & Releases

Bear Lake Prop LLC - Incident: Shale Gas Wastewater Pipeline Spill
March 25, 2025 inspection of a shale gas wastewater pipeline 600 feet east of and serving the Bittinger 4 oil and gas wastewater injection well in **Columbus Township, Warren County** found Bear Lake starting to investigate the extent of contamination from a pipeline spill. The release was discovered on November 8, 2024 by DEP during a routine inspection. DEP expects Bear Lake to begin excavating to identify the source and full extent of the pipeline leak. DEP inspection report.

A major wastewater spill was discovered at the Bittinger 4 injection well by DEP on October 25, 2024 that went unreported by the owner for 109 days. Read more here.

Oil & Gas MGMT Inc. - Violations: Wastewater, Fluids Spill
March 24, 2025 inspection of the Mary Kunkle 5 conventional well in Mount Pleasant Township, Westmoreland County found no effort was made to clean up multiple wastewater and fluid spills on the site. Original violations issued February 27. Well owner did not respond to that violation notice. Violations continued. Response requested by April 9. DEP inspection report.

Coterra Energy Inc. - Violations: Ethylene Glycol Spill
March 18, 2025 inspection at the Zick shale gas well pad in **Lenox Township, Susquehanna County** in response to a notification of an ethylene glycol spill found a leak occurred from a glycol drum inside a secondary containment barrel that was rusted and then onto the well pad. An estimated 47 gallons of glycol was involved, but DEP referred the pad owner to the Act 2 Land Recycling Program for cleanup procedures and standards. Violations issued. Requested response by April 8. DEP inspection report.

2025 Act 2 Oil & Gas Facility Pollution Cleanups
So far in 2025, DEP received or acted on 37 Act 2 Land Recycling notices related to oil and gas facility site cleanups. Read more here.

Defective Shale Well Casing/Cement

Chesapeake Appalachia LLC - Violations: 4 Shale Gas Wells Defective Casing/Cement (41 Months)
March 24, 2025 inspection of the Koromlan 1H, 4H, 6H, 107HC shale gas wells in **Auburn Township, Susquehanna County** during pressure testing resulted in DEP continuing the defective well casing and cement violations originally issued on October 14, 2021. Further testing will be required and evaluated at the end of 2025. DEP inspection report.

Chesapeake Appalachia LLC - Violations: Shale Gas Wells Defective Casing/Cement (14 Years)
March 21, 2025 inspection of the Kipar 5H shale gas well in **Auburn Township, Susquehanna County** to monitor well pressure resulted in DEP continuing the defective well casing and cement violations originally issued on April 11, 2011 for this well. Continuing monitoring. No request for further actions. DEP inspection report.

Repsol Oil & Gas USA LLC - Violations: Shale Gas Defective Casing/Cement
March 12, 2025 inspection of the Camp Comfort shale gas well pad and O7 well in **Middletown Township, Susquehanna County** to monitor well pressures resulted in DEP continuing the defective well casing and cement violations originally issued on September 29, 2017. Continuing monitoring. No request for further action. DEP inspection report.

Leaking Gas

HR McClure - Violations: Leaking Gas, Failure To Submit Reports
March 11, 2025 inspection of the Gordon Williams 02 conventional well in **Franklin Township, Greene County** found the well continues to leak gas and the owner failed to submit annual production (for 5 years), waste generation (or 5 years) and well integrity reports. Original violations issued August 27, 2024. Violations continued. Response requested by March 25. DEP inspection report.

Erosion & Sedimentation

Apollo Resources LLC - Violations: Erosion & Sedimentation, Failure To Submit Reports
March 24, 2025 inspection of the Maria Cicero 2 conventional well in **Grant Township, Indiana County** as a result of a complaint found significant erosion and sedimentation problems at the site and on the access road. Owner also failed to submit annual production, waste generation and well integrity reports. Violations issued. Response requested by April 7. DEP inspection report.

Report Violations

To report oil and gas violations or any environmental emergency or complaint, visit DEP's Environmental Complaint webpage.
Text photos and the location of abandoned wells to 717-788-8990.

Check These Resources

Visit DEP's Compliance Reporting Database and Inspection Reports Viewer webpages to search their compliance records by date and owner.

Sign up for DEP's eNOTICE service which sends you information on oil and gas and other permits submitted to DEP for review in your community.

Use DEP's Oil and Gas Mapping Tool to find if there are oil and gas wells near or on your property and to find wells using latitude and longitude on well inspection reports.

*(**Photos: Row -- Oil & Gas MGMT Inc.** conventional storage tank continues to leak; **Reel Resources, Inc.** leaking for 30 months; Bittinger pipeline release; **EQT Production Co.** failed conventional well plug; **Bear Lake Prop LLC** shale gas waste pipeline leak serving Bittinger 4 wastewater injection well; **Row 2-- Kriebel Natural Gas Co LLC** 2nd conventional gas well explosion (3); **Apex Energy (PA) LLC** abandoned shale gas; **Edward E. & Frederick J. Craig** abandoned conventional well.)*

[**Note:** If you believe your company was listed in error, contact DEP's Oil and Gas Program.]
[**Note:** These may not be all the NOVs issued to oil and gas companies during this time period. Additional inspection reports may be added to DEP's Oil and Gas Compliance Database.]

PA Oil & Gas Industry Public Notice Dashboards:
-- PA Oil & Gas Weekly Compliance Dashboard - March 22 to 28 - Failed To Comply With Well Plugging Order For 63 Months; Abandoned Conventional Well Violations Hit 113; Another Conventional Well Explosion, Same Owner [PaEN]
-- PA Oil & Gas Industrial Facilities: Permit Notices/Opportunities To Comment - March 29 [PaEN]
-- DEP To Hold May 7 Hearing On Proposed Title V Air Quality Permit For Tennessee Gas Pipeline Compressor Station 219 In Jefferson Twp., Mercer County [PaEN]
-- DEP Invites Comments On 401 Water Quality Certification For Rover Pipeline Rover-Bulger Compressor Station, Harmon Creek Meter Station Expansion In Smith Twp., Washington County [PaEN]
-- DEP Invites Comments On Chapter 105 Permit For A MarkWest Liberty 4.5 Mile, 20-Inch Natural Gas Pipeline In Allegheny, Washington Counties Impacting Montour Trail Property [PaEN]
-- DEP Invites Comments On Air Permit For Kratos Cryptocurrency Mining Facility Powered By Natural Gas In Clinton County [PaEN]
-- Susquehanna River Basin Commission Approved 50 Shale Gas Well Pad Water Use General Permits In February [PaEN]
-- DEP Posted 103 Pages Of Permit-Related Notices In March 29 PA Bulletin [PaEN]
Related Articles This Week:
-- Criminal Convictions; Record Penalties, Restitution Of Over $158.3 Million Highlight Big Shale Gas, Related Petrochemical Industry Compliance History In Pennsylvania [PaEN]
-- DEP Reports 575 Water Supply/Stray Gas Complaints About Oil & Gas Operations In Last 2 Years; Investigation Can Take A Year, Sometimes 2-3 To Find Those Responsible [PaEN]
-- Daily Grind Living Next To Oil & Gas Industry: Spills, Polluted Water Supplies, Smells Like Gas, Noise, Air Pollution, Explosions, Truck Traffic, Erosion, Radioactive Waste, Gas Flares, Dust, Lights, Road Dumping Waste, Abandoned Wells [PaEN]
-- DEP To Recommend Environmental Quality Board Accept A Petition For Study To Increase Setbacks From Shale Gas Wells At April 8 Meeting [PaEN]
-- DEP Soliciting Bids On 3rd Conventional Abandoned Oil & Gas Well Plugging Contract For 19 Wells In Clarion, Jefferson Counties At Taxpayer Expense [PaEN]

-- DEP: US Interior Dept. Withdraws Orphan Oil & Gas Well Regulatory Improvement Grant Program To Help Prevent Future Well Abandonments, A Severe Problem In PA [PaEN]
-- Susquehanna River Basin Commission: Low Stream Flows Triggering Restrictions On 19 Shale Gas Water Withdrawals, 17 More Approaching Restrictions [PaEN]
-- Susquehanna River Basin Commission Releases Natural Gas Industry Water Use Report 2019-2023
-- PUC Launches Review Of Electric Grid Impacts From Data Center Growth, Sets April 24 Hearing [PaEN]
-- PJM Interconnection Reliability Initiative Attracts 94 Applications For 26.6 GW Of New Electric Generation Capacity; Reviews To Be Completed By 2026; List Of Projects Not Available Now [PaEN]

NewsClips:

-- WHYY: Bucks County Residents Sue Energy Transfer/Sunoco Pipeline Over Pipeline Leak That Contaminated Their Wells
-- Courier Times: Bucks County Residents Suing Energy Transfer/Sunoco Pipeline For Pipeline Leak That Poisoned Drinking Water
-- Chesapeake Bay Journal - Karl Blankenship: Pennsylvania Caps 300 Abandoned Conventional Oil & Gas Wells In 2 Years
-- The Energy Age Blog: Fracking Under Ohio's Largest State Park Gets Underway; How The Industry Has Changed Guernsey County
-- High Country News: President Halts Historic Orphaned Oil & Gas Well Plugging Program
-- PA Capital-Star: PA Public Utility Commission Sets Hearing On A.I. Data Centers' Impacts On Electricity Grid
-- Utility Dive: PJM Fast-Track Interconnection Process Draws 26.6 GW In New Electric Generation Capacity
-- PennLive Guest Essay: Expect Higher Electric Bills This Summer By As Much As 20% [Thousands Of Energy Projects Stuck In PJM Review] - By Rob Altenburg, PennFuture
-- Kleinman Center For Energy Policy Blog: More Bad Ideas To Promote Natural Gas, More Clean Energy Solutions For Load Growth - By John Quigley, Senior Fellow, Fmr DEP Secretary

[Posted: March 29, 2025] PA Environment Digest

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Analytical Laboratories Inc

1804 N. 33rd Street
Boise, Idaho 83703
Phone (208) 342-5515

Analytical Services Quotation

Printed: 04/15/2026

For: **CHRIS PATE**
1804 N 33RD ST
BOISE, ID 83703

Effective: 04/15/2026
Expires: 05/15/2026

Project: Shelly Brock Fruitland Hydrocarbons
Manager: ANALYTICAL LABORATORIES
Phone: (208) 342-5515 Email: chrispateali@gmail.com

Pricing Summary

Analysis	Method	Qty	TAT (days)	Unit Price	Extended Price
Drinking Water					
Hydrocarbons					
EPA Method 8015C Modified	EPA 8015 MOD	1	10	$150.00	$150.00
Organics					
RSK175MOD Methane, Ethane, Ethene	RSK175 MOD	1	10	$350.00	$350.00
Services					
Sample pickup/collection	SERVICES	1	10	$275.00	$275.00
Non-Drinking Water					
[Group Analysis]					
RCRA 8 Metals for Liquid Samples	varies	1	10	$180.00	$180.00
Semivolatiles					
EPA Method 8270 PAHs by SIM	EPA 8270D SIM	1	10	$350.00	$350.00
Volatiles					
8260 RBCA with additional compounds	EPA 8260B	1	14	$250.00	$250.00
				Bid Total:	**$1,555.00**

Comments: Contact - Shelly Brock (208)559-6127 UShorsepoor@yahoo.com
Fruitland hydrocarbons testing

CHRIS PATE
Environmental Analyst

Rush charges may be applied if sample submission is delayed until the end of analysis hold times.